Eighth International Williston Basin Horizontal Well Workshop

Sponsored by:

North Dakota Geological Survey

Saskatchewan Energy and Mines

May 7 - 9, 2000
Radisson Inn
Bismarck, North Dakota
USA

EDWARD T. SCHAFER
GOVERNOR

State of North Dakota

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100-05922/

GREETINGS

TO THE PARTICIPANTS OF THE

EIGHTH INTERNATIONAL WILLISTON BASIN HORIZONTAL WELL WORKSHOP

BISMARCK, NORTH DAKOTA
MAY 7-9, 2000

Greetings from the Governor's Office and welcome to the *Eighth International Williston Basin Horizontal Well Workshop*. Since its inception, this workshop has served as a forum for the exchange of ideas and technologies that have resulted in much more efficient drilling and production methods.

Saskatchewan Energy and Mines and the North Dakota Geological Survey are to be commended for their vision, which led to this workshop, and for their hard work, which has sustained it. This workshop not only fosters cooperative efforts that benefit the oil industry, it serves as an example to other industries and government agencies of all that can be gained from such international cooperation.

The oil industry plays an important role in our regional economies, and we in North Dakota are glad to host this year's conference, which promises to further the continued exploration and development of the Williston Basin.

Best wishes for an enjoyable and informative workshop!

Sincerely,

Ed Schafer

Edward T. Schafer
Governor

Saskatchewan

Saskatchewan
Energy and Mines

Deputy Minister

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Regina, Canada
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A MESSAGE FROM

SASKATCHEWAN ENERGY AND MINES

On behalf of Saskatchewan Energy and Mines I would like to welcome you to the Eighth Williston Basin Horizontal Well Workshop and the third held in Bismarck.

The original intent of the Workshop was to promote business opportunities on both sides of the border as well as stimulate technology transfer. It is our hope that we continue to achieve both these goals and that the workshop continues to be of value to those attending. We trust that you will take advantage of the workshop to renew acquaintances and to learn more about horizontal wells and opportunities in the Williston Basin.

I hope that you will enjoy the Workshop and your stay in Bismarck.

Ray Clayton
Deputy Minister
Saskatchewan Energy and Mines

May, 2000

Eighth International Williston Basin Horizontal Well Workshop

List of Sponsors

We sincerely thank our industry sponsors for their generous support to help make this a successful meeting!

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Eighth International Williston Basin Horizontal Well Workshop

May 7 - 9, 2000
Radisson Inn Bismarck
Bismarck, North Dakota, USA

Agenda

Sunday, May 7, 2000

12:30 – 5:30 p.m.: **CO_2 Injection for Enhanced Oil Recovery Short Course**; Ray Hattenbach

5:00 p.m. **Registration Desk Open**

6:00 p.m. **Ice Breaker** (6:00 - 9:00 p.m.)

Monday, May 8, 2000

7:00 a.m. **Speakers' Breakfast**

7:30 a.m. **Registration**

8:00 a.m. **Introduction, Welcome, and Opening Remarks**
The Honorable Edward T. Schafer, Governor of the State of North Dakota
Malcolm Wilson: Co-Chairman (Saskatchewan Energy and Mines)
John Bluemle: Co-Chairman (North Dakota Geological Survey)

8:20 a.m. ***Horizontal Drilling Activity in Manitoba***
John N. Fox (Manitoba Conservation, Petroleum and Energy Branch)

8:30 a.m. ***North Dakota Horizontal Drilling Update***
Kelly Triplett (North Dakota Industrial Commission - Oil & Gas Division)

8:40 a.m. ***South Dakota Horizontal Drilling Update***
Gerald (Mack) McGillivray (South Dakota Department of Environment and Natural Resources, Oil & Gas Program)

8:50 a.m. ***Saskatchewan Williston Basin Horizontal Well Update***
*Bob Troyer (Saskatchewan Energy and Mines)
Chris Wimmer (Saskatchewan Energy and Mines)

9:00 a.m. ***Petroleum Technology Research Centre in Regina – Research with a Bottomline***
Roland Moberg (Petroleum Technology Research Centre)

9:25 a.m. **Poster Session - Coffee and Refreshments**

10:45 a.m. ***Greenhouse Gas Policy – How Will It Affect the Oil Industry?***
David Hanly (Saskatchewan Energy and Mines)

11:10 am ***RotaFlex Long Stroke Pumping Units***
Darren Wiltse (Weatherford Artificial Lift Systems)

11:35 am ***Slim Hole Rotary Steerable Short Radius Horizontal Drilling System***
J. David LaPrade (Torch Drilling Services, LLC)

12:00 noon **Lunch: Address by the Honorable Eldon Lautermilch, Minister of Saskatchewan Energy and Mines**

2:00 p.m. ***Microbial Technology Improved Oil Production and Gas Control***
John Barnett (BioConcepts, Inc.)

2:25 p.m. ***In-Situ Acid Production for Completion and Stimulation of Horizontal Wells***
*Ralph E. Harris (Cleansorb Ltd., UK)
Ian D. McKay (Cleansorb Ltd., UK)

2:50 p.m. ***Options for Improving Communication with Fracture Mechanisms for Horizontal Wellbores in the Charles and Mission Canyon Formations of the Williston Basin***
Don Purvis (BJ Services)

3:15 p.m. **Poster Session - Coffee and Refreshments**

4:15 p.m. ***Design and Execution of Horizontal CO_2 Injectors in the Weyburn Unit Field***
Chris Flannery (PanCanadian Petroleum Ltd.)

4:40 p.m. ***Wayne Field Revisited – Horizontal Update***
Jeffrey B. Jennings (GeoResources, Inc.)

5:05 p.m. **Posters: Open until 8:00 p.m.**

Tuesday, May 9, 2000

7:00 a.m. **Speakers' Breakfast**

7:30 a.m. **Registration**

8:00 a.m. **Introduction, Welcome, and Opening Remarks**
Malcolm Wilson (Saskatchewan Energy and Mines)
John Bluemle (North Dakota Geological Survey)

8:05 a.m. ***Signing of the Saskatchewan – North Dakota Memorandum of Understanding***
John Bluemle: Director, North Dakota Geological Survey
Chris Gilboy: Director, Petroleum Geology Branch, Saskatchewan Energy and Mines

8:15 a.m. ***The Magnitude and Rate of Past Global Climate Changes***
John P. Bluemle (North Dakota Geological Survey)

8:40 a.m. ***An Affordable Telemetry Solution***
*Michael Monea (Flatland Exploration)
Don Lang (SiteLink)

9:05 a.m. ***Geosteering in Targets with Subtle Gamma Ray Character Utilizing True Stratigraphic Position Modeling (TSPM)***
Ken Bowdon (Bowdon Energy Consultants)

9:30 a.m. **Poster Session – Coffee and Refreshments**

10:50 a.m. ***Horizontal Exploitation of the Mississippian Mission Canyon Formation "Nesson" Zone, Burke County, North Dakota***
Paul Molnar (Burlington Resources Oil & Gas Company)

11:15 a.m. ***Horizontal Drilling in Flaxton and Woburn Fields, Burke County, North Dakota***
*Jacob D. (Jake) Eisel (Eisel Oil Company)
Michael L. (Mike) Hendricks (Hendricks and Associates)

11:40 a.m. ***Lower Paleozoic Exploration Potential, Williston Basin***
*John C. Horne (Orion International Limited)
Richard F. Inden (LSSI)

12:05 p.m. **Lunch**

1:35 p.m. ***Basement Controls on Red River Sedimentation and Hydrocarbon Production in Southeastern Saskatchewan***
*L. K. Kreis (Saskatchewan Energy and Mines)
D. M. Kent (Consulting Geologist Ltd.)

2:00 p.m. ***Five Theoretical Things Oil Explorers Need to Know about Salt Dissolution and Collapse***
S. P. (Steve) Halabura (North Rim Exploration Ltd.)

2:25 p.m. ***Relationships of Prairie Salt Dissolution and Collapse to Development of Oil Pools in the Williston Basin***
Dean Potter (Sito Geoconsulting Ltd.)

2:50 p.m. ***Oil Charge to the Shaunavon Trend in Southwest Saskatchewan***
*Troy Myers (Rakhit Petroleum Consulting Ltd.)
Dan Barson (Rakhit Petroleum Consulting Ltd.)
Kaush Rakhit (Rakhit Petroleum Consulting Ltd.)

3:15 p.m. **Closing Remarks**

Eighth International Williston Basin Horizontal Well Workshop

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A

Horizontal Drilling Activity in Manitoba

John Fox
Manitoba Conservation
(Petroleum & Energy Branch)

8TH INTERNATIONAL WILLISTON BASIN HORIZONTAL WELL WORKSHOP

HORIZONTAL DRILLING ACTIVITY IN MANITOBA

Last year in Manitoba, 11* of the 28 wells drilled were horizontal. In 1999, horizontal wells accounted for 28.6% of the wells drilled and 41.9% of the drilling meterage in Manitoba, compared to the Western Canadian average of approximately 15% of all completions. The average horizontal well depth was 2002 m, compared to 914 m for vertical wells. The average horizontal well took 11 days to drill and had a horizontal section length of 972 m.

Manitoba's leading horizontal driller in 1999 was Tundra Oil and Gas Ltd. with 9 wells and Alliance with 2 re-entries. During the first quarter of 2000, 4 of the 6 wells drilled in the Province were horizontal.

To date, horizontal wells have been drilled in 34 different pools in 10 of Manitoba's 13 fields. Horizontal wells are not only being used successfully as infill wells between existing producers, but also to develop newly discovered pools, extend existing pool boundaries and to produce trapped oil in mature waterfloods.

The Lodgepole Formation was the favourite target in 1999 with 6 wells drilled, followed by the Mission Canyon 1 with 3 wells and the Mission Canyon 3 with 2 wells. To date, the Lodgepole, MC-1 and MC-3 formations have been the target of 90 of the 100 horizontal wells drilled in Manitoba.

Horizontal well production has increased annually since 1992. In 1999, horizontal well production decreased by 3.7% to 176.2 10^3 m^3 (1 109 000 bbls). In December 1999, 80 of the 100 horizontal wells drilled in Manitoba were on production. Production from these wells totaled 518.3 m^3/d (3260 b/d), an average of 6.5 m^3/d/well (41 b/d/well) and represented 30.5% of the

* includes 3 horizontal re-entries

provincial total. By comparison the average vertical well in Manitoba produces 0.9 m^3/d (5.6 b/d).

Lodgepole and MC-3 horizontal producers accounted for 77% of horizontal well production in 1999. Horizontal producers located in the Pierson, Virden, Tilston and Daly Fields accounted for 81.3% of horizontal well production.

Normalized production for horizontal wells in Manitoba, determined by setting each well back to the same "time-zero", is characterized by a decline rate of approximately 50% in the first 12 months from an initial rate of 17.1 m^3/d (101 b/d), followed by a decline of approximately 20% for the remainder of the well's life. Based on the limited production history for most Manitoba horizontal wells, the majority of which have produced for less than six years, the average well is likely to recover 19 100 m^3 (120,200 bbls).

In Manitoba, a horizontal well is defined as a well that achieves an angle of at least 80° from the vertical for a minimum distance of 100 m. To drill a horizontal well in Manitoba no special approval is required, only a well licence. Horizontal wells receive a HOV of 10 000 m^3 (62,930 bbls) or 10 years production, whichever comes first. Production from horizontal wells is classified as new oil. The value of the horizontal well incentive based on initial productivity of 15 m^3/d (94 b/d) and 20 m^3/d (126 b/d) both declined at 30% p.a. (exponential) is shown below.

Well Classification	Oil Price ($/$m^3$)	HOV (m^3)	Initial Production (m^3/d)	Value of Holiday Oil Volume: Crown Royalty	Value of Holiday Oil Volume: Production Tax
Horizontal	200	10000	15.0	$ 287,636	$ 237,723
Horizontal	200	10000	20.0	$ 323,538	$ 288,479

Where a horizontal well penetrates or drains more than one spacing unit, royalty and production tax is calculated per spacing unit based on production allocated to the spacing unit. The saving associated with paying royalty and production tax for a horizontal well, on a per spacing unit basis should not be overlooked. From the previous example, a well with initial productivity of 20 m^3/d

(126 b/d) declined at 30% p.a. (exponential) will be producing 12.1 m^3/d (76 b/d) after production of the 10 000 m^3 (62,930 bbls) HOV. The Crown royalty rate on total well production would equal 22.8%, compared to 18.9% where the well penetrates or drains three spacing units and 16.9% where four spacing units are penetrated or drained. This translates into monthly royalty savings of $2869 for the three spacing unit case and $4340 for the four spacing unit case. Production tax savings of $3269 and $4920 per month are realized under the same conditions.

In 1999, the Manitoba Government approved the implementation of reductions in Crown royalties and freehold production taxes payable by oil and gas producers. The new "Third Tier Oil " is oil produced from a vertical well drilled or re-entered on or after April 1, 1999, oil produced from an inactive vertical well, activated after April 1, 1999 or, oil produced from an "old oil well" or "new oil" well that, in the opinion of the Director, can be reasonably attributed to an increase in reserves from an enhanced recovery project implemented under The Oil and Gas Act after April 1, 1999.

John Fox, P.Eng.
Chief Petroleum Engineer
Manitoba Conservation
Petroleum and Energy Branch

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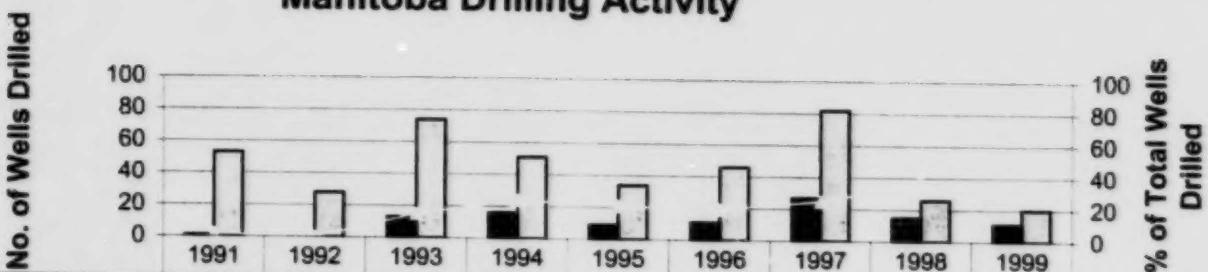
internet: www.gov.mb.ca/em/petroleum

Manitoba Drilling Activity

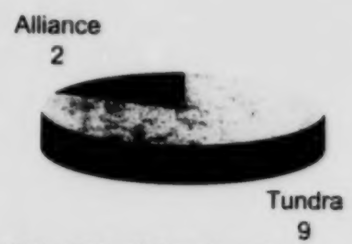


	1991	1992	1993	1994	1995	1996	1997	1998	1999
Horizontal Wells*	1	0	13	16	9	11	27	15	11
Vertical Wells	53	28	74	51	34	46	82	26	20
% of Total Wells Drilled	1.85185	0	14.9425	23.8806	20.9302	19.2982	24.7706	36.5854	28.6

* Includes 1999 Horizontal Re-entries

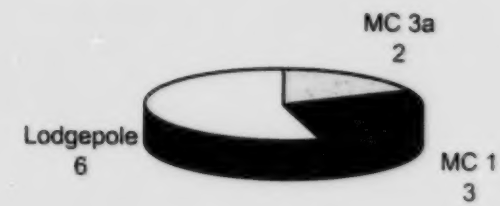
Year

1999 Horizontal Drilling By Operator



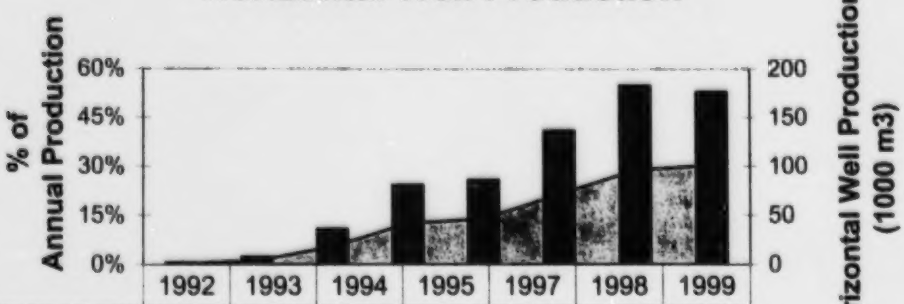
11 Horizontal Wells Drilled/Re-entered

1999 Horizontal Drilling By Formation



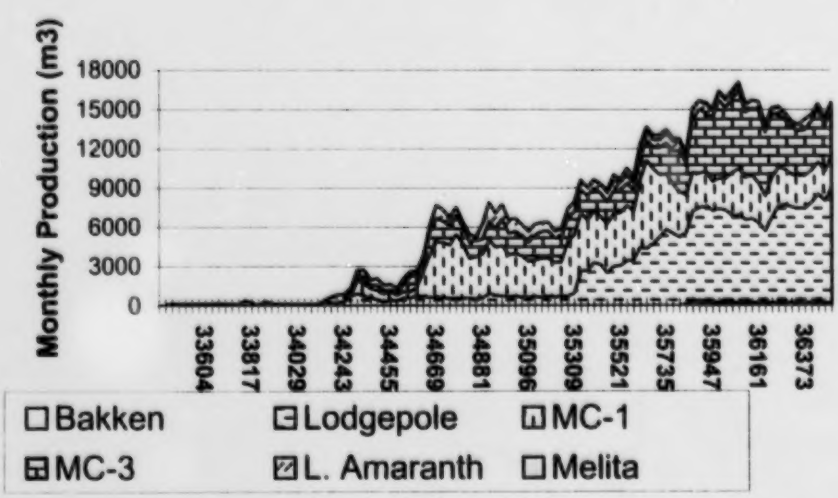
11 Horizontal Wells Drilled/Re-Entered

Horizontal Well Production

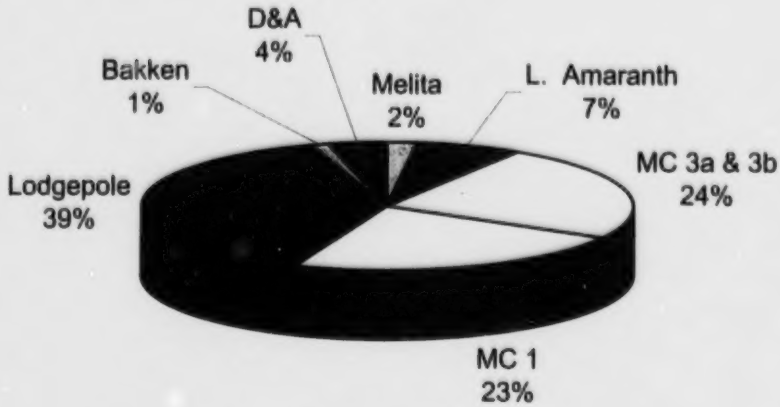


	1992	1993	1994	1995	1997	1998	1999
□ % of Manitoba Production	0.003	0.012	0.055	0.126	0.214	0.288	0.303
■ Horizontal Well Production (103m3)	2.1	7.6	36.1	80.7	136.4	182.8	176.2

Horizontal Well Production By Formation

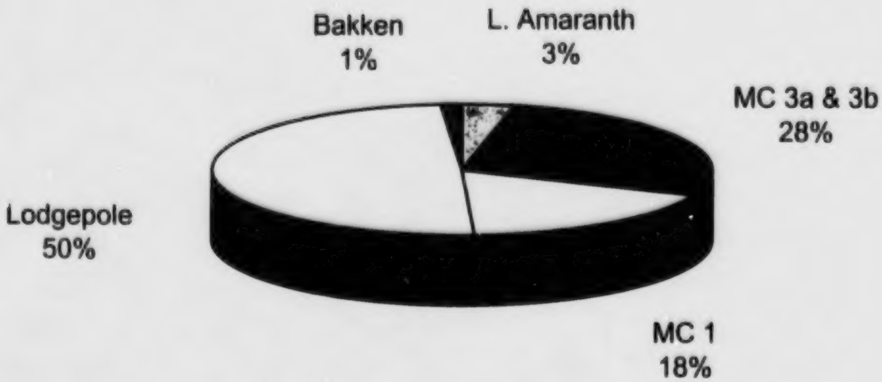


Horizontal Drilling Targets 1991-99



100 Horizontal Wells Drilled

1999 Production by Formation

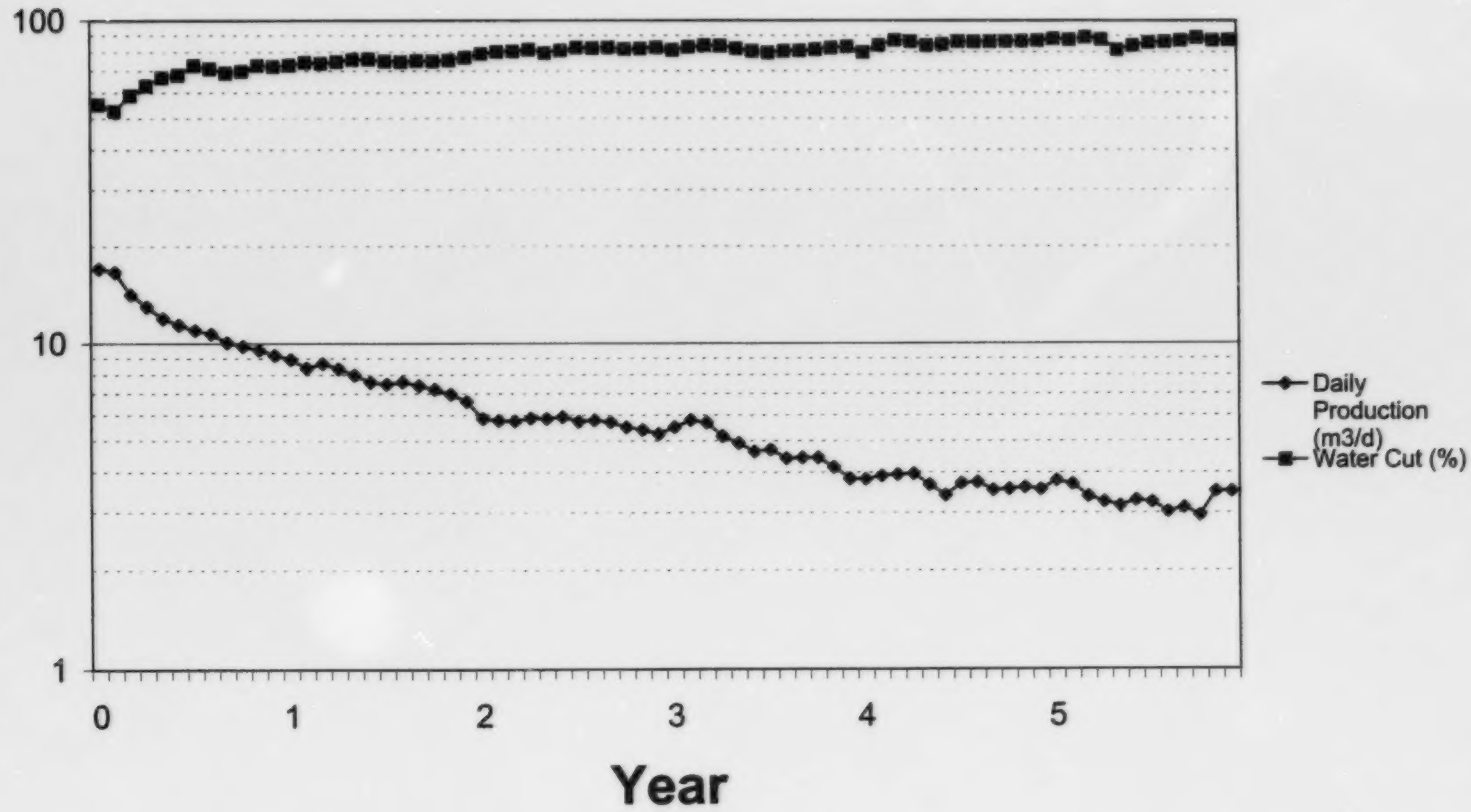


Total Production: 176.2 10^3 m^3

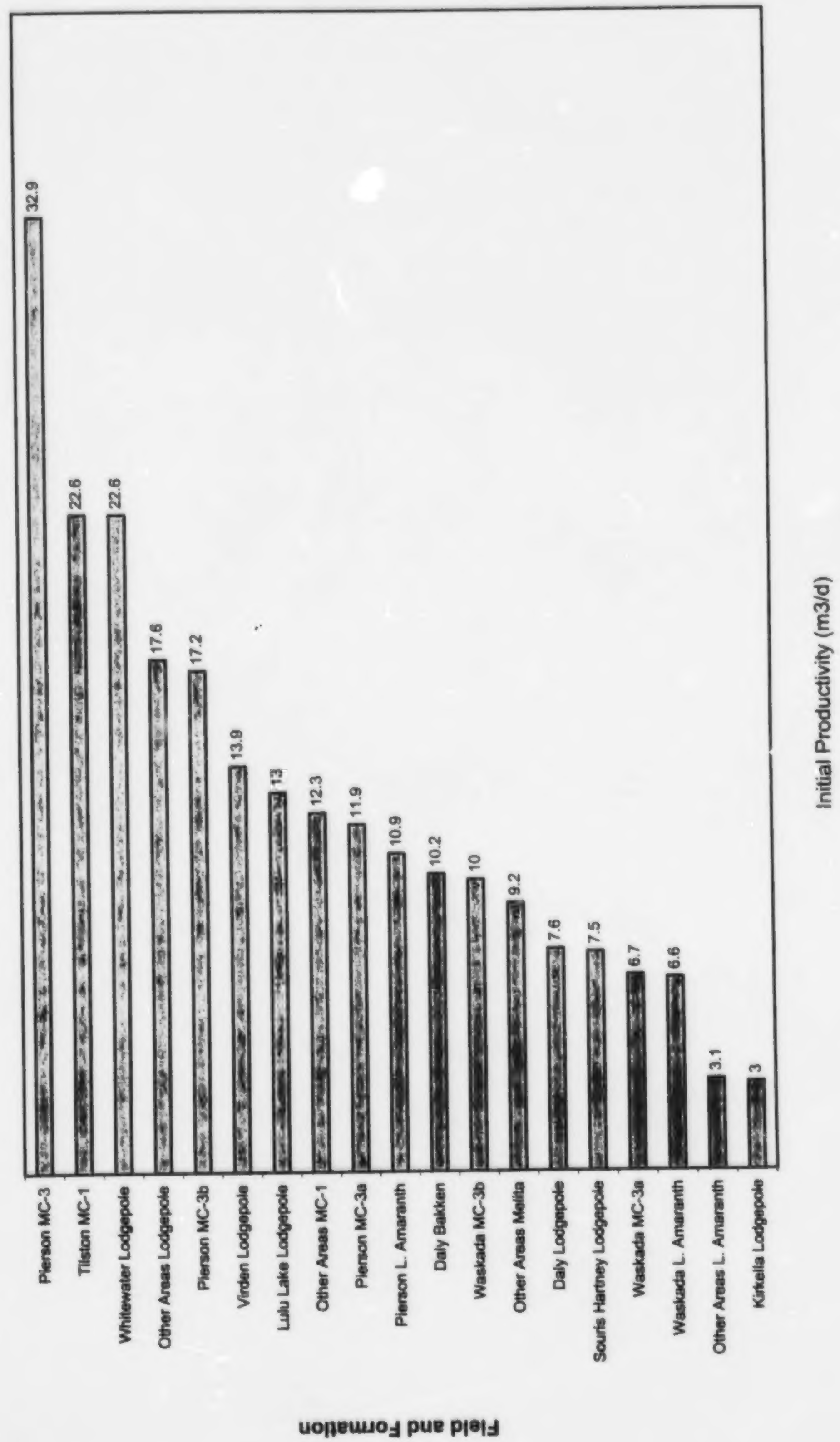
Table 1 - Horizontal Well Production Summary

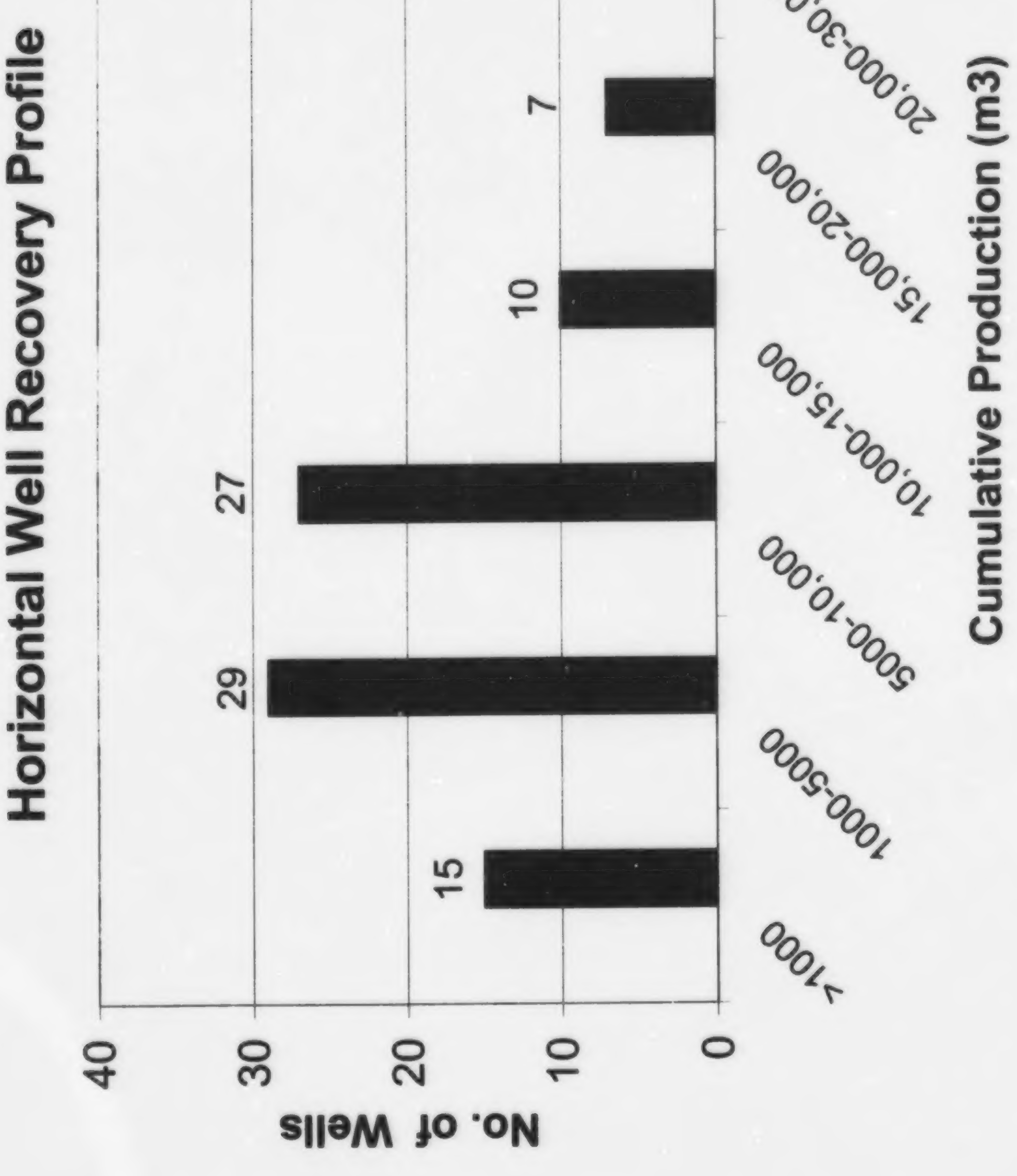
Formation	No. Of Wells Drilled	Cumulative Production (31-Dec-99) (m3)	Average Initial Productivity 1st (6) Months (m3/d)	No. of Wells On Production Dec-99	Daily Production Dec-99 (m3/d)	Daily Production per Well Dec-99 (m3/d/well)	Average Measured Depth (m)	Average Hzntl. Section Length (m)
Melita	2	4901	9.2	0	0	0	912	374
L. Amaranth	7	48806	9.2	6	15.1	2.5	2426	1290
MC 3a & 3b	24	176434	16.0	21	122.2	5.8	1872	785
MC 1	23	222313	18.1	18	84.1	4.7	1722	746
Lodgepole	39	250867	10.9	34	290.4	8.5	1500	712
Bakken	1	5291	10.2	1	6.5	6.5	1770	851
D & A	4	—	—	—	—	—	1251	285
Total	100	708612	13.7	80	518.3	6.5	1689	782

Normalized Horizontal Well Production



Initial Horizontal Well Productivity By Field and Formation




Horizontal Well Recovery Profile
No. of Wells
0
10
20
30
40
15
29
27
10
7
5
2
<1000
1000-5000
5000-10,000
10,000-15,000
15,000-20,000
20,000-30,000
30,000-50,000
Cumulative Production (m3)

1999 HORIZONTAL WELL PRODUCTION SUMMARY

Apr. 13/00

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HZNTL SECTION LENGTH (m)	INIT. PRODUCTIVITY 1ST 6 MON. OR LESS (m3/d)	DAILY PRODUCTION Dec/99 (m3/d)	CUMULATIVE PRODUCTION Dec/99 (m3)	STATUS
Melita	4-22-16-29	Renaissance Energy	Other Areas Melita A	796	277	10.5	SI	2 079.0	COOP
	A4-22-16-29	Renaissance Energy	Other Areas Melita A	784	226	7.8	SI	2 821.7	COOP
		2nd Leg	KOP-610 m	854	244				
Lower Amaranth	2-26-1-29	Williston Wildcatters	Pierson - L. Amaranth L	1652	408	-	-	0.4	ABD PROD
	9-25-1-26	NCE Petrofund	Waskada L. Amaranth A	1703	675	6.6	1.9	4 064.0	COOP
		2nd leg	KOP-1086 m	1675	589				
	4-15-1-24	Tundra Oil and Gas	Other Areas L. Amaranth I	2216	1237	3.1	1.4	1 527.6	COOP
		2nd leg	KOP-1011 m	1490	479				
Lower Amaranth/ Mission Canyon 3	7-15-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	1871	624	4.3	2.4	6 677.0	COOP
		2nd leg	KOP-1492 m	1805	313				
		3rd leg*	KOP-1270 m	1829	559	7.0			
	11-11-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	2465	1283	15.5	4.2	17 302.5	COOP
	1-16-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	1709	586	14.2	2.6	5 529.3	COOP
	11-10-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	1838	692	10.9	1.6	7 070.3	COOP
	2-19-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	2481	1353	16.8	3.5	12 164.3	COOP
		2nd leg	KOP-1164 m	1980	816				
Mission Canyon 3	5-30-1-28	Rideau Petroleums	Pierson - MC 3	1360	218	-	-	-	COMP
		2nd leg	KOP-1156 m	1397	241				
	5-3-2-26	NCE Petrofund	Waskada MC 3b B	1624	600	12.0	2.9	7 863.6	COOP
	12-5-3-28	Home Oil	Pierson MC 3b B	1494	415	7.0	SI	1 464.9	COOP
	1-26-1-26	NCE Petrofund	Waskada MC 3a A	1811	788	6.5	1.3	4 163.1	COOP
	14-34-1-26	NCE Petrofund	Waskada MC 3b B	1581	543	8.0	1.5	4 674.6	COOP

*3rd leg on Production July 26, 1995, 1st & 2nd leg on Production June 28, 1993

1999 HORIZONTAL WELL PRODUCTION SUMMARY

Apr. 13/00

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HZNTL SECTION LENGTH (m)	INIT. PRODUCTIVITY 1ST 6 MON. OR LESS (m3/d)	DAILY PRODUCTION Dec/99 (m3/d)	CUMULATIVE PRODUCTION Dec/99 (m3)	STATUS
Mission Canyon 3	10-35-1-26	NCE Petrofund	Waskada MC 3a I	1410	368	6.8	2.3	6 071.4	COOP
		2nd leg	KOP-1341 m	1587	246				
	3-18-3-28	Tundra Oil and Gas	Pierson MC 3b B	1877	791	25.8	9.5	25 879.5	COOP
	12-4-3-28	Tundra Oil and Gas	Pierson MC 3b B	997	49	-	-	57.8	ABD PROD
	7-11-3-29	Tundra Oil and Gas	Pierson MC 3a C	1215	127	4.9	-	-	COOP
		2nd leg	KOP-1094 m	1697	603				
		3rd leg**	KOP-1215 m	1820	605	5.5	2.0	4 700.5	
	A3-18-3-28	Tundra Oil and Gas	Pierson MC 3b B	1888	820	21.8	8.4	26 322.1	COOP
	11-17-3-28	Tundra Oil and Gas	Pierson MC 3a B	2003	945	15.5	8.4	15 157.1	COOP
	3-22-3-28	Todd Ballantyne	Pierson MC 3a B	1658	561	0.7	0.8	647.3	COOP
	11-6-3-29	Search Energy	Pierson MC 3 C	1605	440	18.5	0.8	4 742.7	COOP
		2nd leg	KOP-1170 m	1464	294				
	5-12-3-29	Tundra Oil and Gas	Pierson MC 3a C	1844	763	26.7	18.0	15 041.7	COOP
	12-6-3-29	Search Energy	Pierson MC 3 C	1537	402	44.5	10.3	14 552.1	COOP
		2nd leg	KOP-1154 m	1511	357				
	A5-12-3-29	Tundra Oil and Gas	Pierson MC 3a C	1286	195	22.5	SI	7 531.9	COOP
		2nd leg	KOP–1164 m	1966	802				
	A11-6-3-29	Search Energy	Pierson MC 3 C	1568	430	42.7	8.6	13 329.9	COOP
		2nd leg	KOP–1152 m	1605	453				
	6-6-3-29	Search Energy	Pierson MC 3C	1558	446	19.7	4.4	5 281.3	COOP
	8-12-3-29	Tundra Oil and Gas	Pierson MC 3b B	1759	691	17.3	7.8	4 435.4	COOP
		2nd leg	KOP–1275 m	1856	581				
	14-5-3-29	Search Energy	Pierson MC 3a F	1184	99	8.1	2.2	846.7	COOP
		2nd leg	KOP-1088 m	1384	296				
	14-6-3-29	Search Energy	Pierson MC 3 C	1384	300	28.5	7.3	6 810.9	COOP
		2nd leg	KOP-1100 m	1343	243				
	15-17-3-28	Tundra Oil and Gas	Pierson MC 3a A	1522	465	8.4 (5 months)	8.5	923.8	COOP
		2nd leg	KOP-1142 m	1951	809				
	13-12-3-29	Tundra Oil and Gas	Pierson MC 3a C	1876	801	3.5 (5 months)	5.7	406.5	COOP
		2nd leg	KOP-1184 m	1920	736				

**3rd leg on Production Sep. 20,1996, 1st & 2nd leg on Production Sep. 14, 1995

1999 HORIZONTAL WELL PRODUCTION SUMMARY

Apr. 13/00

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HZNTL SECTION LENGTH (m)	INIT. PRODUCTIVITY 1ST 6 MON. OR LESS (m3/d)	DAILY PRODUCTION Dec/99 (m3/d)	CUMULATIVE PRODUCTION Dec/99 (m3)	STATUS
Mission Canyon	1-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1680	570	26.7	1.2	18 830.5	COOP
1	A1-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1724	691	26.8	6.3	40 159.4	COOP
	2-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1864	756	33.3	3.7	29 471.5	COOP
		2nd leg	KOP-1282 m	1657	375				
	3-31-5-29	Tundra Oil and Gas	Tilston MC 1 A	1628	580	13.9	6.0	4 607.3	COOP
		2nd leg	KOP-1082 m	1584	502				
	6-8-6-28	Alliance Energy Inc.	Other Areas - MC 1 E	1554	495	14.5	3.2	6 116.3	COOP
		2nd leg***	KOP-1150 m	1991	841				
	12-15-6-29	Tundra Oil and Gas	Tilston MC 1 C	1335	328	22.5	1.5	12 027.4	COOP
	12-32-5-29	Tundra Oil and Gas	Tilston MC 1 A	1538	485	14.7	SI	3 980.1	COOP
	11-6-6-28	Alliance Energy Inc.	Other Areas - MC 1 E	1424	778	3.9	2.1	914.7	COOP
		2nd leg****	KOP-1130 m	1969	839				
	A3-31-5-29	Tundra Oil and Gas	Tilston MC 1 A	1463	412	5.4	0.6	1 644.6	COOP
	10-31-5-29	Tundra Oil and Gas	Tilston MC 1 A	1763	697	8.3	0.8	2 754.8	COOP
	11-15-6-29	Tundra Oil and Gas	Tilston MC 1 C	1123	125	27.0	3.4	17 104.1	COOP
		2nd leg	KOP-1048 m	1378	330				
	B1-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1732	697	29.6	3.7	17 868.2	COOP
	12-9-6-29	Tundra Oil and Gas	Tilston MC 1 C	1284	289	36.4	2.5	15 136.5	COOP
		2nd leg	KOP-1052 m	1238	186				
		3rd leg	KOP-1137 m	1630	493				
	8-14-6-27	CanNat Resources	Other Areas MC 1 H	1780	789	13.9	1.8	8 856.8	COOP
	2-16-6-26	CanNat Resources	Other Areas MC 1 G	1087	247	9.6	SI	3 197.2	COOP
		2nd leg	KOP-960 m	1229	269				
	6-14-6-27	CanNat Resources	Other Areas MC 1 H	1649	738	12.3	5.0	6 594.5	COOP
	14-9-6-26	Rigel Oil & Gas	Other Areas MC 1 G	1355	463	38.7	SI	7 880.1	COOP
	15-16-6-26	CanNat Resources	Other Areas MC 1 G	1700	837	10.9	1.9	4 196.4	COOP
	A14-9-6-26	Rigel Oil & Gas	Other Areas MC1 G	1270	395	0.5	-	109.0	ABD PROD

***2nd leg drilled in December 1999, 1st leg on Production on Nov. 6, 1994

****2nd leg drilled in December 1999, 1st leg on Production on Feb. 24, 1995

1999 HORIZONTAL WELL PRODUCTION SUMMARY

Apr. 13/00

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HZNTL SECTION LENGTH (m)	INIT. PRODUCTIVITY 1ST 6 MON. OR LESS (m3/d)	DAILY PRODUCTION Dec/99 (m3/d)	CUMULATIVE PRODUCTION Dec/99 (m3)	STATUS
Mission Canyon	4-16-6-26	CanNat Resources	Other Areas MC 1 G	1299	459	11.8	SI	1 087.2	COOP
1	C1-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1481	464	17.2	8.1	7 164.4	COOP
		2nd leg	KOP–1127 m	1690	563				
	5-15-6-29	Tundra Oil and Gas	Tilston MC 1 C	1576	590	31.5	19.7	11 892.3	COOP
	16-25-1-24	Tundra Oil and Gas	Other Areas MC 1 I	1481	457	6.8 (5 months)	6.6	719.8	COOP
		2nd leg	KOP-1091 m	1376	285				
		3rd leg	KOP-1147 m	1285	138				
Lodgepole	8-30-10-28	Tundra Oil and Gas	Daly Lodgepole E	1220	331	5.4	2.4	10 908.1	COOP
	5-18-12-29	Neutrino Resources	Kirkella Lodgepole Daly C	885	104	2.7	-	651.5	SWD
	6-17-12-29	Neutrino Resources	Kirkella Lodgepole Daly B	1219	455	3.0	-	515.2	SWD
	5-17-12-29	Neutrino Resources	Kirkella Lodgepole Daly B	1320	523	3.3	0.5	1 284.1	COOP
	7-22-9-29	Rideau Petroleums	Daly Lodgepole D	1338	472	2.1	0.7	1 653.5	COOP
	14-22-8-28	Herc Oil	Daly Lodgepole O	1584	621	1.4	SI	461.6	COOP
		2nd leg*****	KOP-874 m	1366	492				
	3-17-6-22	Tundra Oil and Gas	Souris Hartney Lodgepole Virden A	1543	816	10.3	4.7	21 821.7	COOP
	15-17-6-22	Tundra Oil and Gas	Souris Hartney Lodgepole Virden A	1359	612	4.8	SI	5 521.4	COOP
		2nd leg	KOP-780 m	1624	844				
	14-16-6-22	Tundra Oil and Gas	Souris Hartney Lodgepole Virden A	1386	634	7.4	5.0	9 997.7	COOP
	6-33-8-28	Herc Oil	Daly Lodgepole Q	1197	321	2.6	SI	83.1	COOP
	3-20-11-26	Upton Resources	Virden Lodgepole A	1271	499	4.7	5.2	5 183.4	COOP
	6-26-11-26	Chevron Canada	Virden Lodgepole A	1135	461	-	-	-	J&A
		2nd leg	KOP-677 m	1102	425	5.2	3.8	4 663.2	COOP
	7-33-11-26	Chevron Canada	Virden Lodgepole A	1118	390	27.7	22.7	29 721.5	COOP

******2nd leg on Production on Mar. 28, 1999, 1st leg on Production on Oct. 19, 1993

1999 HORIZONTAL WELL PRODUCTION SUMMARY Apr. 13/00

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HZNTL SECTION LENGTH (m)	INIT. PRODUCTIVITY 1ST 6 MON. OR LESS (m3/d)	DAILY PRODUCTION Dec/99 (m3/d)	CUMULATIVE PRODUCTION Dec/99 (m3)	STATUS
Lodgepole	12-34-11-26	Chevron Canada	Virden Lodgepole A	1138	411	11.2	3.3	6 415.1	COOP
	13-29-10-28	Tundra Oil and Gas	Daly Lodgepole E	1390	542	15.4	6.5	12 814.3	COOP
		2nd leg	KOP-873 m	1520	647				
	4-11-10-28	Chevron Canada	Daly Lodgepole A	1555	678	3.4	3.8	5 189.7	COOP
	15-2-10-28	Chevron Canada	Daly Lodgepole A	1551	667	7.4	4.2	6 646.8	COOP
	13-15-11-26	Chevron Canada	Virden Lodgepole A	1383	623	9.1	2.2	7 078.0	COOP
	16-30-11-28	Mountcliff Resources	Virden Lodgepole A	1465	755	20.5	10.8	9 822.7	COOP
		2nd leg	KOP-755 m	1131	376				
	13-26-1-21	Tundra Oil and Gas	Lulu Lake Lodgepole WL B	1912	806	12.6	9.5	8 233.7	COOP
		2nd leg	KOP-1425 m	1903	478				
	11-16-2-21	Enron Oil	Other Areas Lodgepole WL E	1451	373	17.6	5.5	8 625.3	COOP
	4-2-3-21	Enron Oil	Whitewater Lodgepole WL B	1440	553	4.5	2.4	2 619.3	COOP
	1-20-9-25	Chevron Canada	Virden Lodgepole C	1207	540	8.6	7.2	5 160.0	COOP
	3-12-10-28	Chevron Canada	Daly Lodgepole A	1155	400	1.9	0.8	936.4	COOP
	15-12-10-28	Chevron Canada	Daly Lodgepole A	1159	409	6.2	2.4	3 233.7	COOP
	1-31-9-28	Chevron Canada	Daly Lodgepole A	1238	428	2.2	SI	633.9	COOP
	3-4-12-26	Chevron Canada	Virden Lodgepole A	1156	534	6.1	1.8	2 882.9	COOP
	15-6-11-25	Chevron Canada	Virden Lodgepole B	1095	505	1.7	0.8	893.4	COOP
	15-22-11-26	Chevron Canada	Virden Lodgepole A	1303	671	7.5	6.1	5 168.0	COOP
	10-25-10-26	Chevron Canada	Virden Lodgepole B	1275	660	24.5	9.6	10 977.2	COOP
	12-13-10-28	Chevron Canada	Daly Lodgepole A	1417	644	6.2	5.1	4 123.3	COOP
	5-30-10-28	Tundra Oil and Gas	Daly Lodgepole E	1905	1103	36.9	33.3	26 653.6	COOP
	16-19-11-26	Tundra Oil and Gas	Virden Lodgepole A	1323	583	11.9	9.7	7 265.5	COOP
		2nd leg	KOP-792 m	1689	897				
	15-29-9-25	Tundra Oil and Gas	Virden Lodgepole C	1333	641	9.5	4.6	4 115.7	COOP
	A13-26-1-21	Tundra Oil and Gas	Lulu Lake Lodgepole WL B	1848	760	13.4	12.2	3 646.9	COOP
	1-17-6-22	Tundra Oil and Gas	Souris Hartney Lodgepole Virden A	1707	955	7.4	3.8	1 734.9	COOP
	2-29-9-25	Tundra Oil and Gas	Virden Lodgepole C	1213	533	33.4	26.6	8 130.1	COOP
		2nd leg	KOP-753 m	1320	567				
	4-20-3-21	Tundra Oil and Gas	Whitewater Lodgepole WLA	1689	825	40.6 (4 months)	40.8	4 665.2	COOP

1999 HORIZONTAL WELL PRODUCTION SUMMARY

Apr. 13/00

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HZNTL SECTION LENGTH (m)	INIT. PRODUCTIVITY 1ST 6 MON. OR LESS (m3/d)	DAILY PRODUCTION Dec/99 (m3/d)	CUMULATIVE PRODUCTION Dec/99 (m3)	STATUS
Lodgepole	3-32-11-26	Mountcliff Resources	Virden Lodgepole A	1217	507	26.3 (1 month)	26.3	735.8	COOP
		2nd leg	KOP- 764 m	1464	700				
	15-30-11-26	Tundra Oil and Gas	Virden Lodgepole	1426	724	-	-	-	COMP
		2nd leg	KOP- 862 m	1362	500				
	11-29-9-25	Tundra Oil and Gas	Virden Lodgepole	1615	924	-	-	-	COMP
	2-17-3-21	Tundra Oil and Gas	Whitewater Lodgepole	1526	675	-	-	-	COMP
		2nd leg	KOP- 873 m	1400	527				
	1-20-3-21	Tundra Oil and Gas	Whitewater Lodgepole	1540	672	-	-	-	COMP
Bakken	6-33-10-29	Tundra Oil and Gas	Daly Bakken A	1770	851	10.2	6.5	5 290.7	COOP

C

North Dakota Horizontal Drilling Update

Kelly Triplett
North Dakota Industrial Commission
Oil and Gas Division

North Dakota Horizontal Drilling Update

Kelly Triplett – Horizontal Drilling Supervisor
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Drilling activity in North Dakota was dismal at best during the first months of 1999; the depressed oil price brought the drilling rigs to a complete stand still. For the first time in North Dakota oil field history we were without a drilling rig turning to the right and during the month of February 1999, the rig count (vertical and horizontal) was ZERO. The oil price dropped to a low of $6.64 for a monthly average in December 1998 (Amoco's posted price for ND Sweet). Oil prices started to slowly rebound and by the end of 1999 were again strong but the prolonged price depression had taken its toll.

North Dakota issued 34 horizontal permits in 1999. The Madison Group accounted for the majority with 29 permits, the Red River 3 permits, the Stonewall 1 permit, and the Bakken 1 permit. Permit renewals are still being issued for the Red River wells in Slope and Bowman Counties. A trend that has developed over the past few years is re-entry of existing wellbores. Re-entering these wellbores and drilling multiple horizontal legs have been quite successful and are helping to rejuvenate existing oil fields. Horizontal legs can be drilled in these existing wellbores at a substantial cost saving which can be very significant in a depressed market.

The number of horizontal wells drilled in the state matched the number of permits at 34. Of the 34 wells drilled 20 were new wells and 14 were re-entries. The Madison Formation saw 27 wells drilled: 15 new wells and 12 re-entries. The Red River Formation had 4 wells drilled: 2 new wells and 2 re-entries. The Bakken, Stonewall and Duperow Formations each had 1 new well drilled. The success ratio for horizontal wells remains extremely high with 97% of the wells drilled being completed as producers.

The total horizontal production for 1999 was 6.78 million barrels of oil. This total is 20.6% of the overall production for North Dakota, which was 32.87 million barrels. The Red River Formation accounted for 58% of the horizontal production in 1999, with 3.9 million barrels of oil. It is now the top cumulative horizontal producer with oil accumulations of 21.7 million barrels since the beginning of the horizontal play in October 1994. The Commission has recently approved three secondary recovery units in Bowman County. If the secondary recovery units in the Cedar Hills Field are ratified this year, the Red River Formation will continue to be a strong horizontal producer.

The Madison Formation is the second leading horizontal oil producer with 33% of the horizontal production in 1999, producing 2.25 million barrels of oil. This formation has accumulated 7.4 million barrels of oil from horizontal wellbores. There is strong evidence that re-entries will continue to play a large part in the development of the horizontal Madison Formation.

The Bakken Formation contributed 8% of the horizontal production in 1999, producing 535,855 barrels of oil. The horizontal oil accumulation for the Bakken still ranks number two with 18.97 million barrels of oil having been produced. Although we haven't seen much for activity in the Bakken Formation over the past few years the decline of the existing wells has leveled out and it will continue to produce for many years.

The other formations that had horizontal activity in 1999 were the Duperow, and Stonewall Formations each having only one well drilled. One percent of the horizontal production comes from the Duperow, Stonewall, Winnipegosis, and the Spearfish/Charles Formations combined. Over time, and with higher oil prices, we could see continued development in these formations.

Although there wasn't a lot of activity in 1999, the most active areas were in Williams, Mountrail, and McKenzie counties on the Nesson anticline, in Burke County where Madison wells with tri-lateral legs were being drilled, and in Billings County. Statewide production (horizontal and vertical) dropped off by 7.4% for 1999 from 35.5 million barrels in 1998 to 32.8 million barrels in1999. Indications are for a better year in 2000 with higher oil prices and increasing activity.

North Dakota oil production is assessed a gross production tax and an oil extraction tax. All existing wells and new wells drilled are assessed the 5% gross production tax. The oil extraction tax is 4% for all wells drilled after April 27, 1987 and 6.5% for all wells drilled prior to April 27,1987. The North Dakota Legislature has passed numerous exemptions to the oil extraction tax. The following waivers on the oil extraction tax can be obtained:

- All production from a stripper well property
- 10 years following production from a two-year inactive well
- 10 years following the date incremental production commences from a tertiary recovery project
- 5 years following the date incremental production commences from a secondary recovery project
- The first 24 months of production for all new horizontal wells
- The first 15 months of production for new vertical wells
- The 12 months following a qualifying workover project
- 9 months following production from a horizontal re-entry well
- The first 60 months of production for all wells located within the boundary of an Indian Reservation

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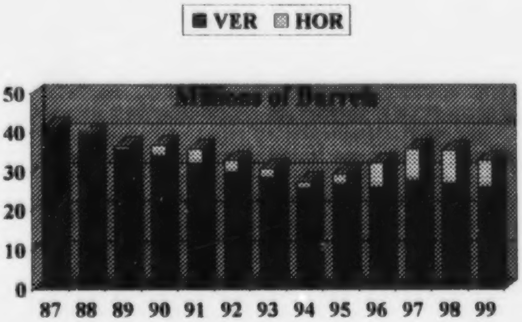
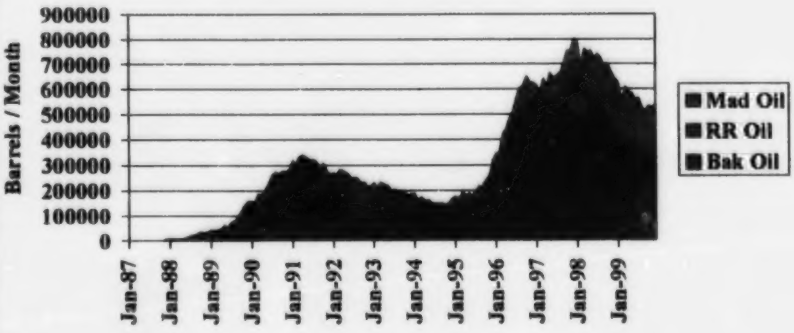
NORTH DAKOTA HORIZONTAL UPDATE

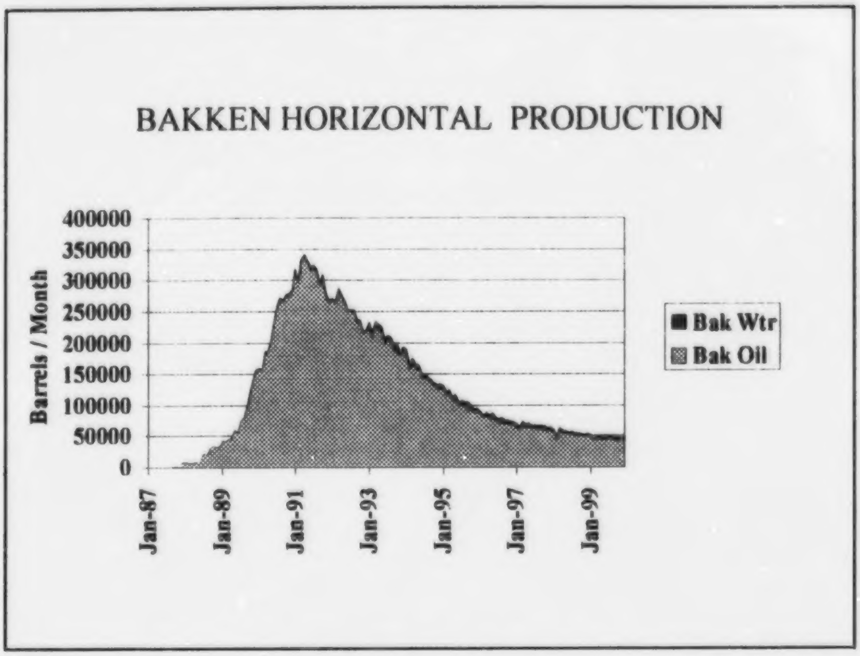
Kelly Triplett
Horizontal Drilling Supervisor

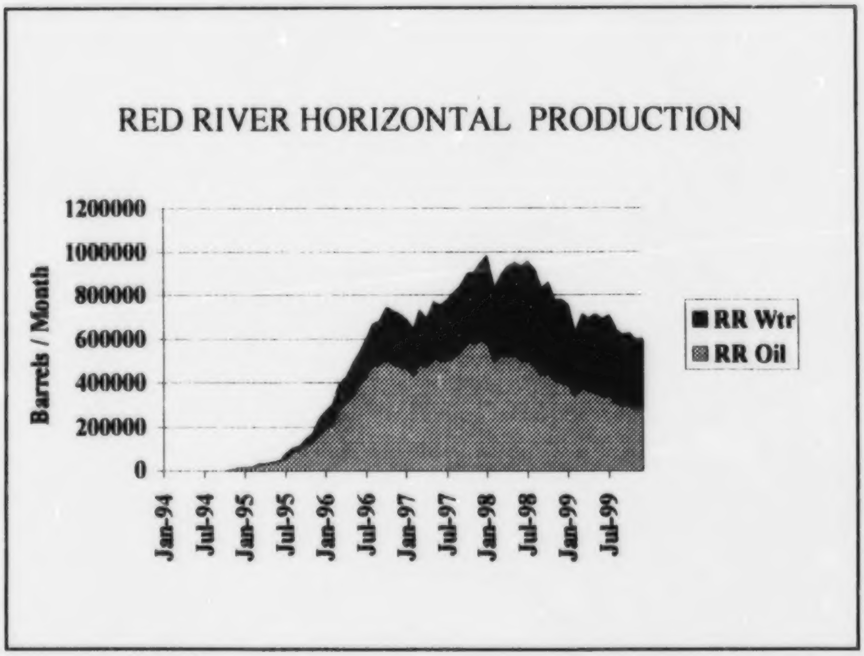
NORTH DAKOTA
YEARLY OIL PRODUCTION



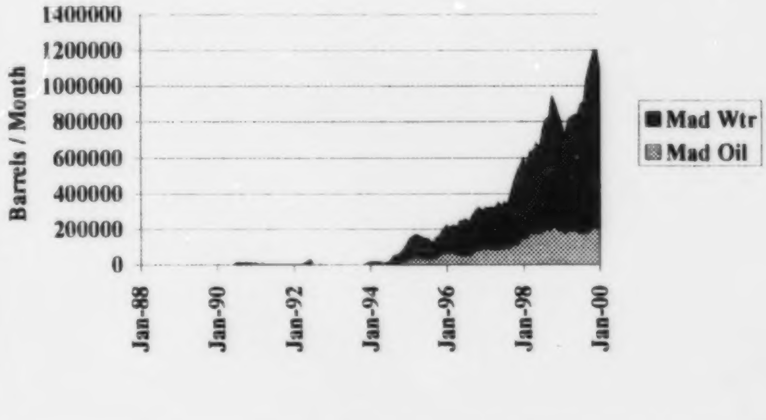
HORIZONTAL OIL PRODUCTION




BAKKEN HORIZONTAL PRODUCTION
400000
350000
300000
250000
200000
150000
100000
50000
0
Barrels / Month
Jan-87
Jan-89
Jan-91
Jan-93
Jan-95
Jan-97
Jan-99
Bak Wtr
Bak Oil

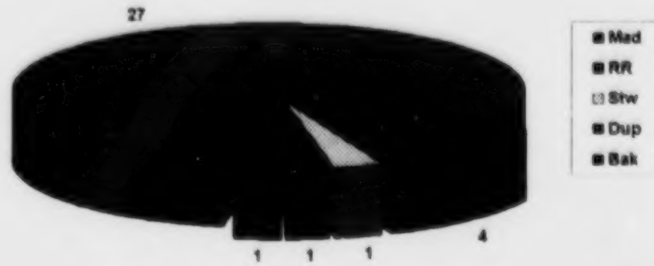

RED RIVER HORIZONTAL PRODUCTION
1200000
1000000
800000
600000
400000
200000
0
Barrels / Month
Jan-94
Jul-94
Jan-95
Jul-95
Jan-96
Jul-96
Jan-97
Jul-97
Jan-98
Jul-98
Jan-99
Jul-99
RR Wtr
RR Oil

MADISON HORIZONTAL PRODUCTION

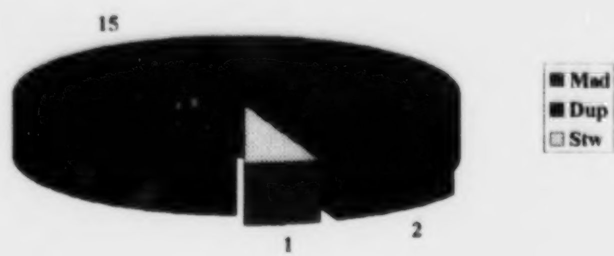


NUMBER OF HORIZONTAL PERMITS ISSUED IN 1999

HORIZONTAL WELLS DRILLED IN 1999
NEW AND RE- ENTRY WELLS

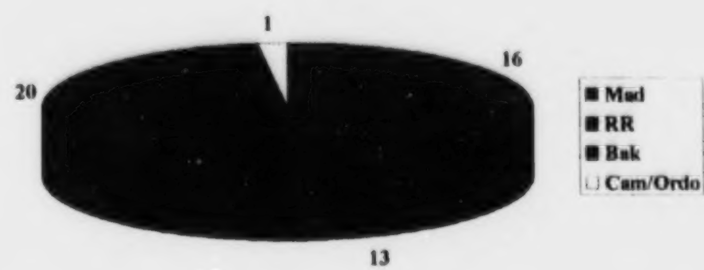


HORIZONTAL WELL COMPLETIONS IN 1999

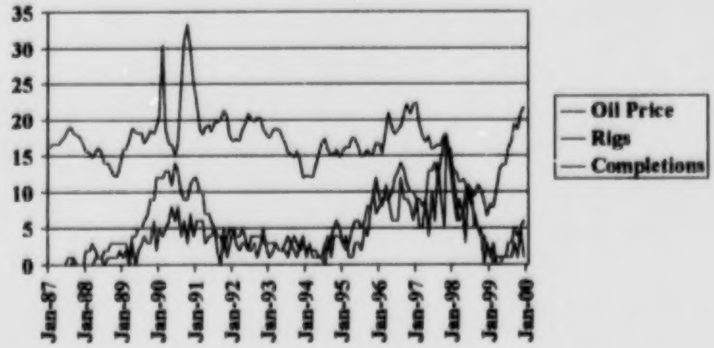


NUMBER OF HORIZONTAL WELLS ON PRODUCTION AS OF 1-1-2000

TOTAL NUMBER OF HORIZONTAL DRY HOLES AS OF 1-1-2000



HORIZONTAL WELL STATISTICS



North Dakota Tax Incentives

- All production from a stripper well property
- 10 yrs following production from a 2-yr inactive well
- 10 yrs following the date incremental production commences from a tertiary recovery project
- 5 years following the date incremental production commences from a secondary recovery project
- The first 24 months of production for all new Hz wells
- The first 15 months of production for new vertical wells
- 12 months following a qualifying workover project
- 9 months following production from a horizontal reentry
- The first 60 months of production for all wells located within the boundary of an Indian Reservation

Welcome to the North Dakota Industrial Commission, Oil and Gas Division, home page.

The Oil and Gas Division regulates the drilling and production of oil and gas in North Dakota. Many services are available from the Bismarck office.

Statutes and Rules for the Conservation of Oil and Gas (PDF 2258K)
Industrial Commission Hearing Dockets (Last update 3-30-2000) New dockets are in Adobe PDF
List of Unitized Pools in North Dakota

Hearing! Changes are proposed in the North Dakota Administrative code. Hearing to be held May 5, 2000.

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Fee services

- Field order index with complete order text
- Daily Activity reports Daily reports as of 2-14-2000 are in Adobe PDF
- 1999-2000 monthly well production data (Last update 3-9-2000)
- Weekly active drilling rig list
- Well files in Adobe PDF. Current well file numbers available: 1 through 2800

Sign up form for fee services

D

South Dakota Horizontal Drilling Update

Gerald (Mack) McGillivray
South Dakota Department of Environment and Natural Resources Oil & Gas Program

SOUTH DAKOTA HORIZONTAL DRILLING UPDATE

Gerald (Mack) McGillivray
South Dakota Department of Environment and Natural Resources
Oil & Gas Program

Following the trend of the rest of the Williston Basin, and probably mostly due to record low crude prices, 1999 was not a good year for horizontal drilling in South Dakota. There were only three wells horizontally drilled last year.

But, In many respects, horizontal drilling is still relatively new to South Dakota, with most of the horizontal drilling activity having occurred since 1994. The exception is one well drilled in 1988. From 1994 to 1996 horizontal drilling was on the rise, with two wells drilled in 94, three in 95, and seven in 96. In 1997 however, drilling activity fell to five wells, and only one horizontal re-entry was drilled and completed in 1998. The bad news continued in 1999, when only two new horizontal wells were drilled and one vertical well was re-entered and drilled horizontally (Figure 1). There is good news for 1999 however, all three wells were producers.

Since 1988, 18 new horizontal wells have been drilled, and 4 existing vertical wells have been re-entered and horizontally drilled. Of those 22 wells, 11 are currently producing; 5 are currently injecting (4 injecting water as part of a water flood project, 1 is injecting air as part of a "fire flood" project); 1 has been temporarily abandoned; and 5 have been plugged and abandoned (Figure 2).

All of the horizontal wells have been drilled in the Williston Basin in Harding County (Figure 3), and most have been drilled in and around Buffalo Field (Figure 4). All of the wells have targeted the Ordovician Red River Formation, primarily the "B" Porosity Zone (Figure 5). The lengths of the lateral sections range from 504 feet to 5109 feet (Figure 6).

To date, the operators conducting horizontal drilling projects and the number of wells they drilled are; Continental Resources (10), Citation Oil & Gas (4), Merit Energy (2), Luff Exploration (3), Burlington Resources (1), Summit Resources (1), and Samedan (1) (Figure 7). Other operators that have established horizontal spacing but have not commenced drilling horizontal wells are Wyoming Resources, Sage Energy, and Kep Energy.

Prior to 1997, oil production from horizontal wells had not contributed significantly to South Dakota's overall crude oil production. Beginning in 1994, one horizontal well produced 4211 barrels, only .2% of the total crude oil output for the state, 1,453,139 barrels. In 1995, two horizontal wells produced 27,422 barrels, about 2% of the state total of 1,352,436 barrels. In 1996, six horizontal wells produced 44,164 barrels, about 3.5% of the state total of 1,257,476 barrels. In 1997, eleven horizontal wells (two wells were converted to injection midway in the year) contributed 126,925 barrels, about 9.5% of the state total of 1,334,041 barrels. In 1998, nine horizontal wells contributed 203,323 barrels, about 17% of the state total of 1,206,463 barrels.

Last year, production from eleven horizontal wells contributed 174,872 barrels, about 15.9% of the state total of 1,100,028 barrels (Figure 8). Although the total production was down from the previous year, it should be noted that several wells were shut-in at various times, and the three new horizontal wells did not start producing until late in the year.

A closer look at 1999 production figures shows that although monthly oil production from vertical wells remained fairly consistent through most of the year, production from horizontal wells increased significantly. In January, the horizontal wells produced 12,357 barrels, about 13.6% of the state total of 90,954 barrels. In December the horizontal wells produced 17,963 barrels, about 17.9% of the state total of 100,119 barrels (Figure 9). The increase in both vertical and horizontal production is due primarily to new wells and shut-in wells starting back up.

Although horizontal drilling activity in South Dakota decreased drastically in 1998 and 1999 from 1997 levels, there are some signs drilling activity may increase in the near future. One indication of this is the increase in leasing and spacing activity in Harding County. Currently, over 90,000 acres has been spaced for horizontal drilling in Harding County (Figure 10). Most of the horizontal spacing units have been set at 640 acres, or a typical governmental section, with up to 2 wells allowed per section. Another indication is the current trend of re-entering marginally producing vertical wells and drilling horizontal laterals.

Another incentive for increasing horizontal drilling in South Dakota may be the recent update of the Procedures of the Board of Minerals and Environment (Article 74:09) and the Oil and Gas Conservation Rules (Article 74:10), which supplement the oil and gas conservation statute, cited as SDCL Chapter 45-9. The new rules became effective September 8, 1996. For example, prior to that date, an operator desiring to conduct a directional drilling operation had to file a petition with the secretary of the DENR for a contested case hearing before the South Dakota Board of Minerals and Environment (BME), a citizen advisory board appointed by the Governor. After notice and hearing, the BME could issue a permit for the directional drilling operation. Since the requirements for contested case hearings can be a time consuming and expensive process, and the rules did not address the complex issues associated with horizontal drilling, the DENR decided to address these issues with an update of the rules. Along with requiring some additional information to the application to drill a horizontal well, the major change in the rules that affects horizontal drilling is the addition of a new chapter 74:10:11:01, called the "Notice of Recommendation Procedure" or NOR. The NOR allows the DENR Oil & Gas Program staff to deal administratively with applications to drill horizontal wells if they are uncontested (Figure 11). Other applications that can now be handled by the NOR are exception locations, abandoning oil and gas fields, directional holes, multiple zone completions, commingling of oil from separate pools, and underground injection control (UIC) applications or modifications.

Although South Dakota has not yet enjoyed the amount and success of horizontal activity that our neighbors to the North have, there is great potential for increased drilling, horizontal and vertical, in the state. The Williston Basin encompasses portions of 16 counties in the state, over 28,000 sq. mi., and close to 18 million acres.

Currently, only two of those counties, Harding and Dewey, have oil and gas production (Figure 12). And this production only affects about 30,000 acres. This leaves a vast, essentially unexplored, area that has the potential to greatly increase the oil and gas reserves of South Dakota.

FOR MORE INFORMATION CONTACT:

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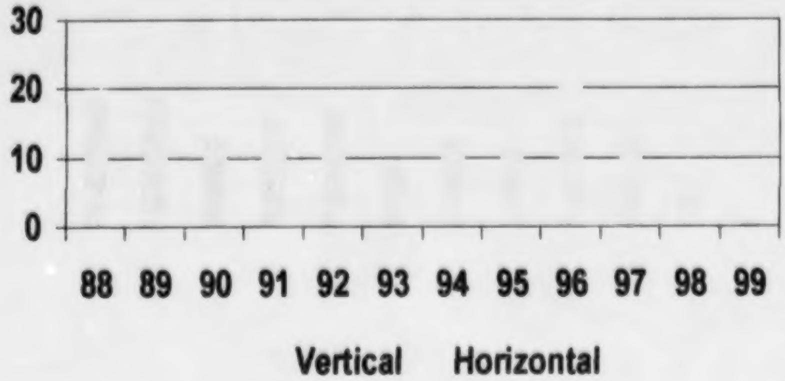
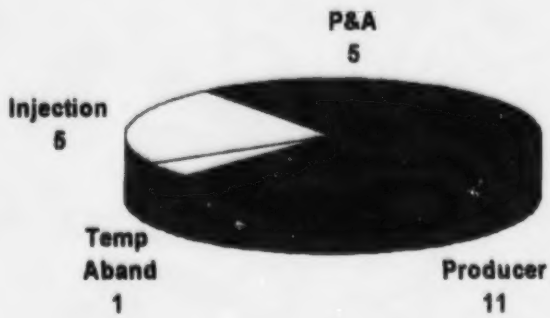
OR MACK MCGILLIVRAY (GEOLOGIST) email: mack.mcgillivray@state.sd.us
SOUTH DAKOTA DEPARTMENT OF ENVIRONMENT & NATURAL RESOURCES
OIL & GAS PROGRAM
2050 WEST MAIN, SUITE #1
RAPID CITY, SD 57702-2493
PHONE: (605)394-2229 FAX: (605)394-5317

South Dakota Horizontal Drilling
1988 - 1999



SD DENR - OIL & GAS PROGRAM 3/22/00 FIGURE 1

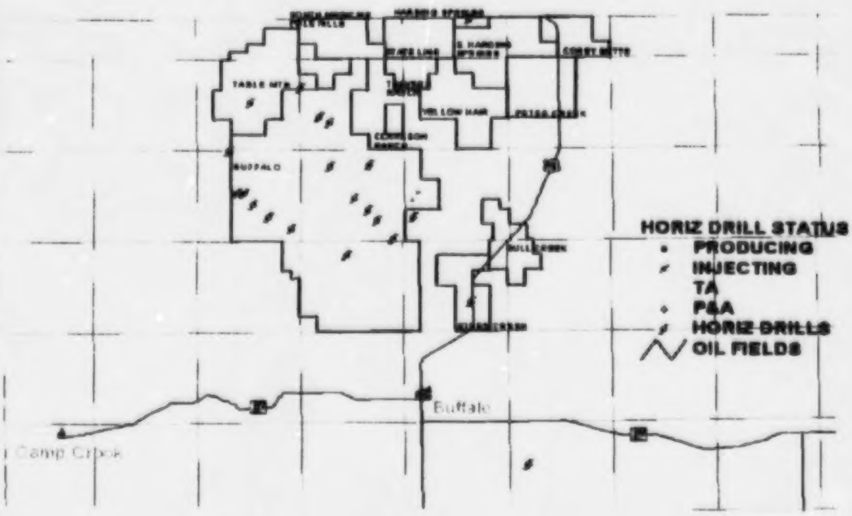
South Dakota Horizontal Wells
22 Wells as of March 2000



SD DENR - OIL & GAS PROGRAM 3/22/00 FIGURE 2

EXTENT OF THE WILLISTON BASIN IN SOUTH DAKOTA

SD DENR - OIL & GAS PROGRAM 3/22/00 FIGURE 3



SD DENR - OIL & GAS PROGRAM 3/22/00 FIGURE 4

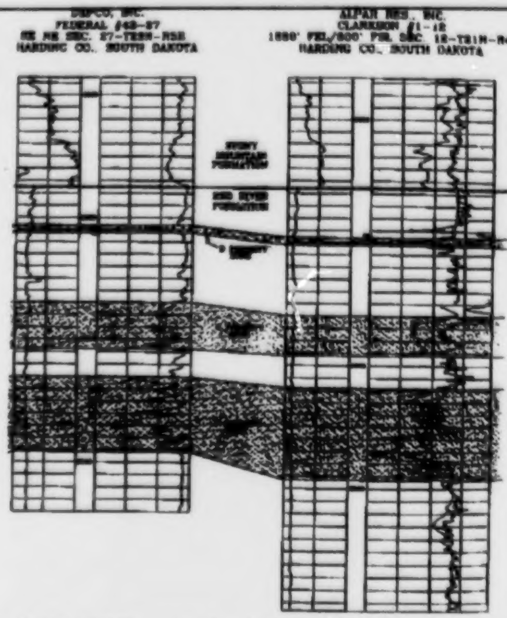
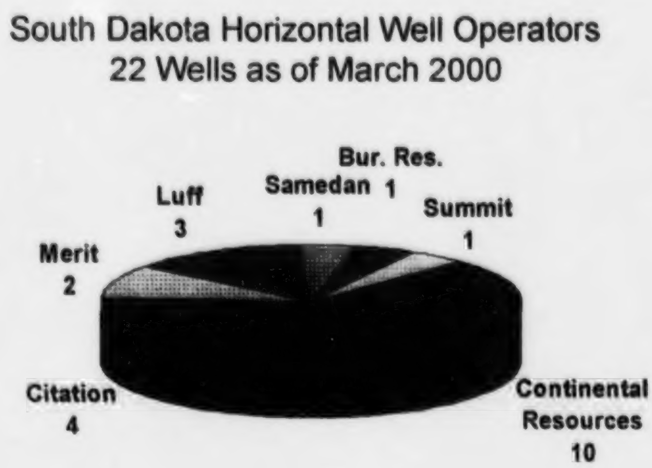


Figure 5 - Exhibit by Continental Resources, Inc. to SD Board of Minerals and Environment Hearing 9/20/95.

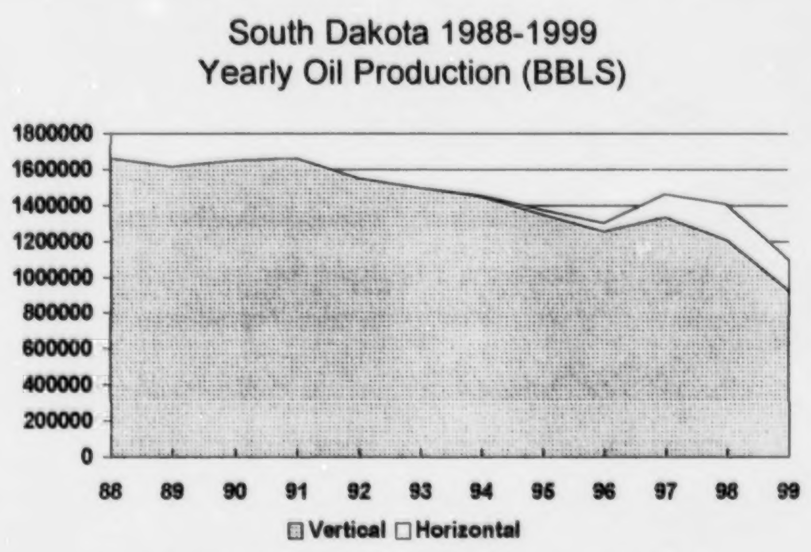
HORIZONTAL WELLS 1988-1999

Well Name					
[illegible]	Meridian Oil Co	P&A	12/16/88	TVD-9124, MD-10,086	962
[illegible]	Citation Oil & Gas	Producer	9/25/94	TVD-8404,MD-11,200	2796
[illegible]	Citation Oil & Gas	Injection (Water)	11/6/94	TVD-8422, MD-11,300	2878
[illegible]	Meridian Energy	TA	10/29/93	TVD-8324, MD-11,878	3554
[illegible]	Continental Resources	P&A	11/25/93	TVD-8714, MD-13,202	4488
[illegible]	Meridian Energy	Producer	12/3/95	TVD-8857, MD-12,661	3804
[illegible]	Samedan Oil	P&A	7/12/96	TVD-8667, MD-13,127	4460
[illegible]	Continental Resources	Injection (Air)	9/11/96	TVD-8572, MD-13,406	4834
[illegible]	Continental Resources	Producer	10/17/96	TVD-8524, MD-13,633	5109 (longest lateral)
[illegible]	Citation Oil & Gas	Producer (Re-entry)	11/5/96	TVD-8444, MD-11,084	2640
[illegible]	Luff Exploration	Injection (Water)	11/15/96	TVD-9040, MD-10,059	1019
[illegible]	Citation Oil & Gas	Producer (Reentry)	11/23/96	TVD-8470, MD-9374	904
[illegible]	Continental Resources	Producer	11/24/96	1 TVD-8330, MD-11,144	2814
				2 TVD-9042, MD-12,782	3740
[illegible]	Continental Resources	Producer	1/19/97	TVD-9625, MD-12,031	2406
[illegible]	Continental Resources	Producer	3/1/97	1 TVD-8646, MD-13,303	4657
				2 TVD-8527, MD-12,806	4279
[illegible]	Continental Resources	Injection (Air)	8/8/97	TVD-8390, MD-11,836	3448
[illegible]	Summit Resources	TA	8/10/97	TVD-8073, MD-11,404	3331
[illegible]	Continental Resources	Producer	9/10/97	1 TVD-8958, MD-11,003	2045
				S1 TVD-8935, MD-10,768	1833
				S2 TVD-8933, MD-11,012	2099
				2 TVD-8949, MD-11,592	2643
[illegible]	Luff Exploration	Producer (Re-entry)	10/12/98	TVD-9134, MD-9638	504
[illegible]	Continental Resources	Producer	8/29/99	TVD-8679, MD-10274	1595
[illegible]	Luff Exploration	Producer (Re-entry)	9/29/99	TVD-8783, MD-10,799	2016
[illegible]	Continental Resources	Producer	10/1/99	TVD-8602, MD-12,710	4108

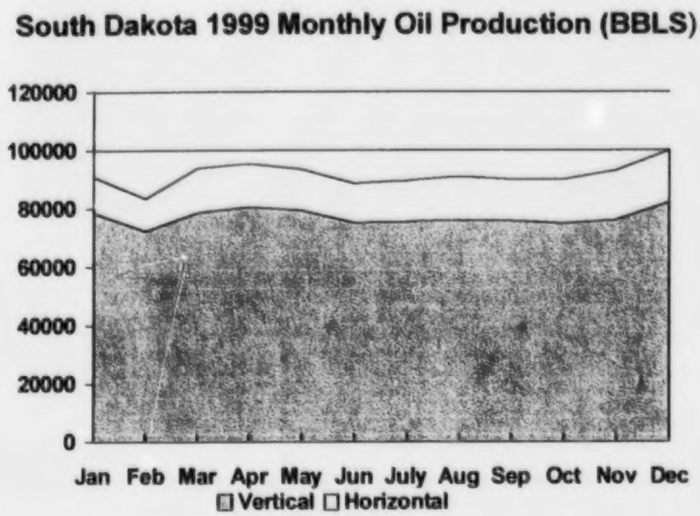
SD DENR - OIL & GAS PROGRAM 3/22/00 FIGURE 6



SD DENR - OIL & GAS PROGRAM 3/22/00 FIGURE 7

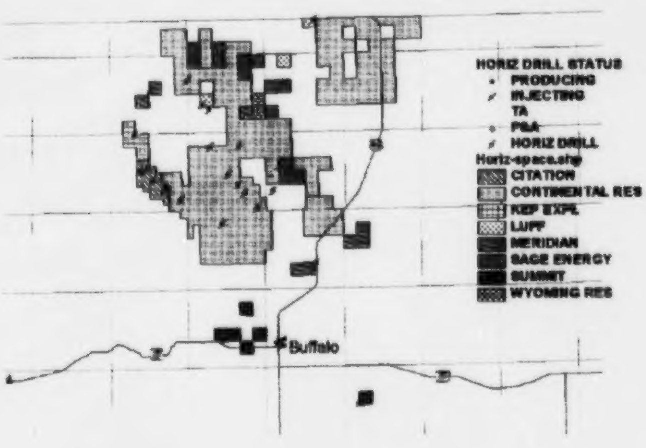


SD DENR - OIL & GAS PROGRAM 3/22/00 FIGURE 8



SD DENR - OIL & GAS PROGRAM 3/22/00 FIGURE 9

HORIZONTAL SPACING IN HARDING COUNTY, SOUTH DAKOTA

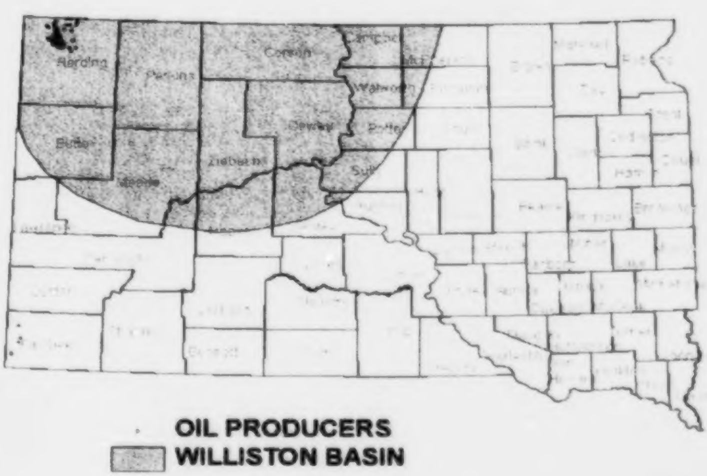


SD DENR - OIL & GAS PROGRAM 3/22/00 FIGURE 10

Notice of Recommendation Procedure

- Application is made and reviewed by DENR
- DENR publishes NOR, usually with conditions.
- Allow 20 days from publication date for comments.
- If no objections, O&G Supervisor approves the application administratively.
- If objections made, a hearing is scheduled before the Board of Minerals and Environment.

SD DENR - OIL & GAS PROGRAM 3/22/00 FIGURE 11



SD DENR - OIL & GAS PROGRAM 3/22/00 FIGURE 12

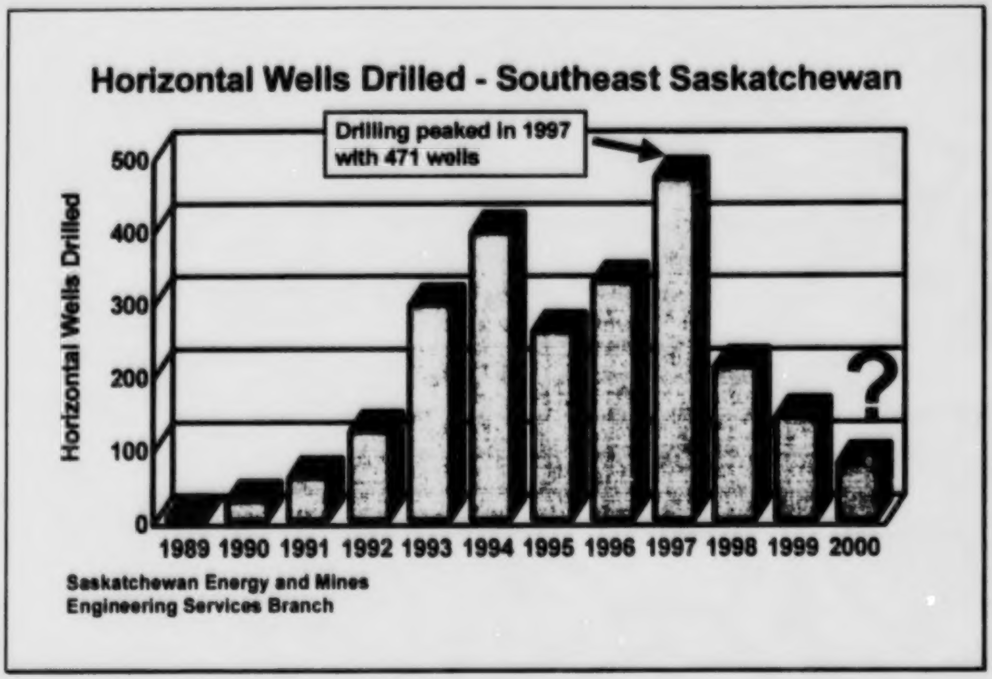
E

Saskatchewan Williston Basin Horizontal Well Update

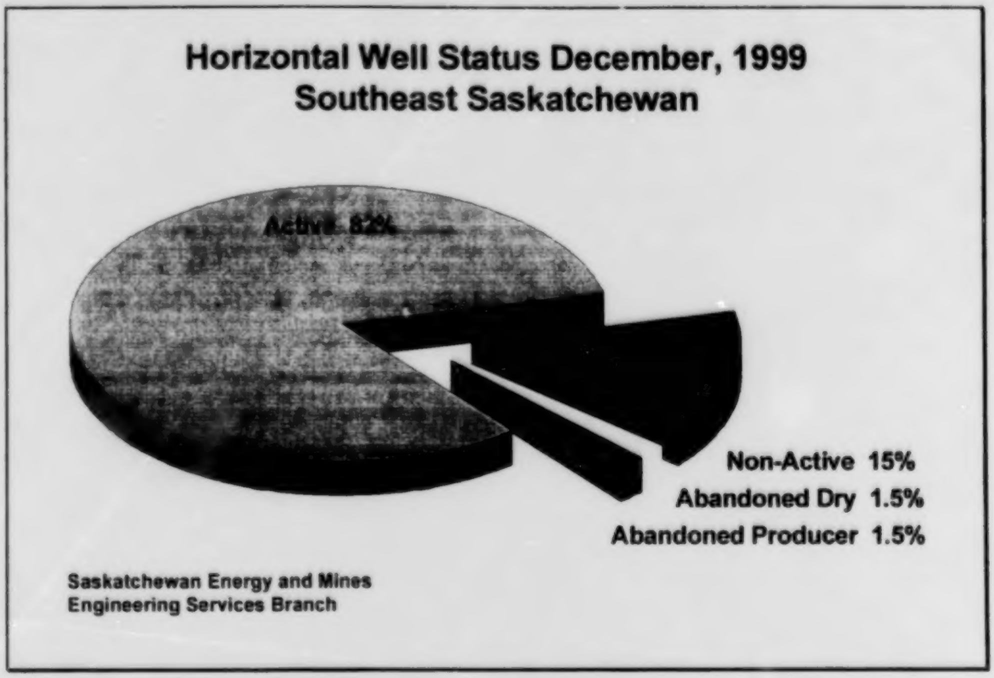
Chris Wimmer, P.Eng.
Speaker - Bob Troyer
Saskatchewan Energy and Mines

SASKATCHEWAN WILLISTON BASIN HORIZONTAL WELL UPDATE

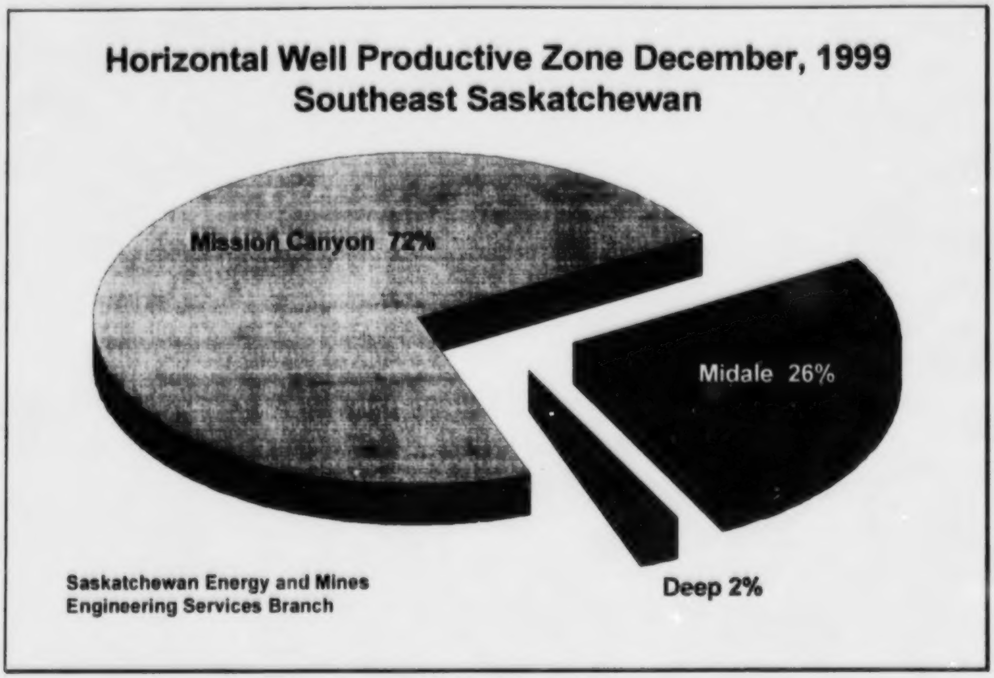
Chris Wimmer, P.Eng.
Saskatchewan
Energy and Mines



- The first horizontal well was drilled in southeast Saskatchewan in August, 1989
- Horizontal drilling increased rapidly with a peak of 471 wells in 1997
- To the end of 1999, 2659 horizontal wells had been drilled
- There are over 850 wells with multiple lateral sections (almost 2000 laterals in all)
- Drilling has increased in recent months mainly due to improved oil prices

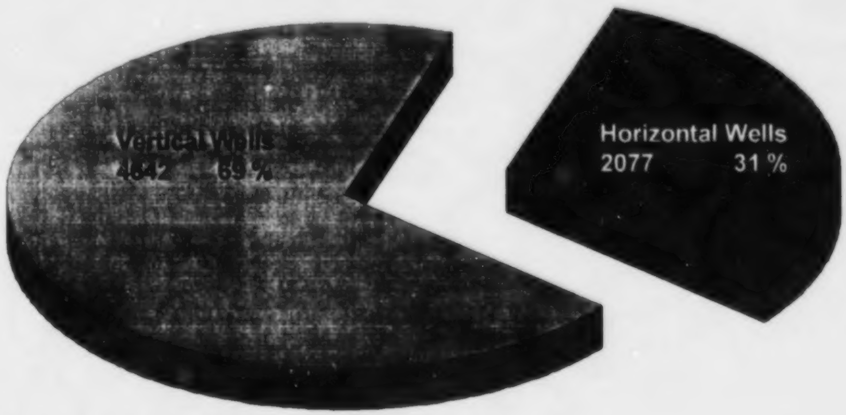


- At December, 1999, 1901 of the horizontal wells drilled were classified as active
- 342 were non-active
- 32 had been dry and abandoned
- Only 37 producing horizontal wells had been abandoned or recompleted as vertical wells



- Most of the horizontal wells in southeast Saskatchewan have been drilled in the Mississippian carbonates
- 1584 wells have been drilled in the Mission Canyon group, primarily in the Frobisher-Alida Beds
- 565 wells have been drilled in the Midale Beds
- 46 wells have been drilled in zones deeper than the base of the Mississippian, 32 in the Ordovician Red River Formation

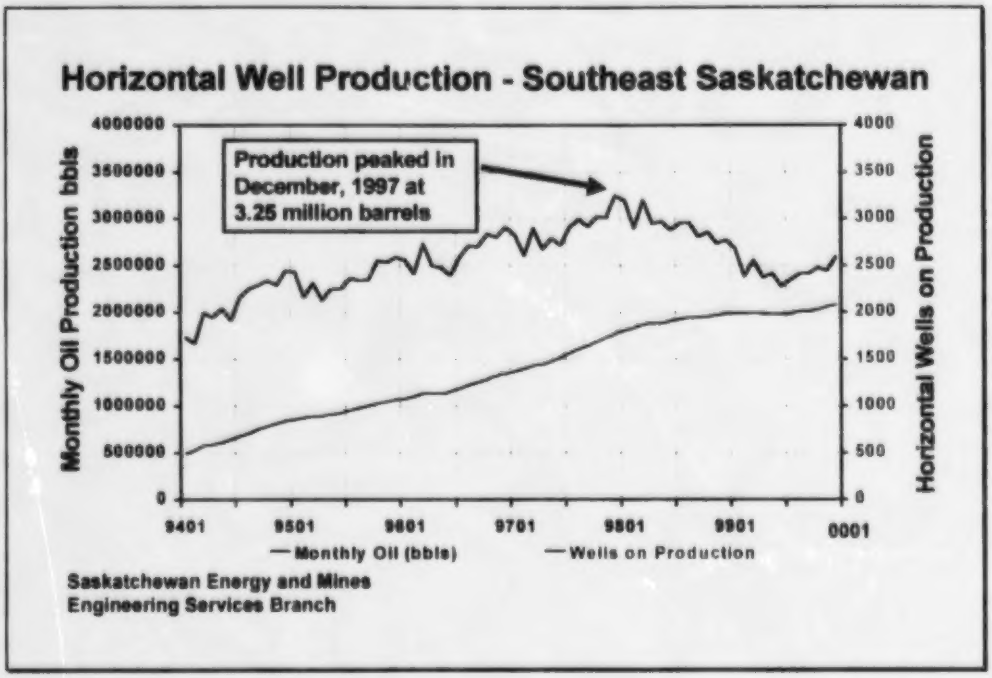
Producing Oil Wells December, 1999
Southeast Saskatchewan



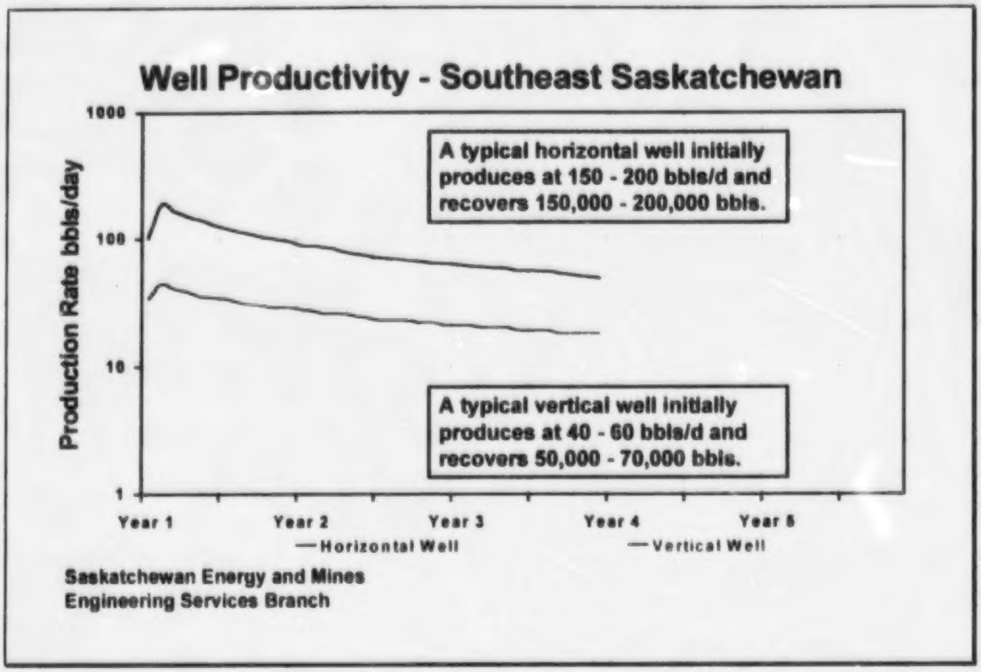
Saskatchewan Energy and Mines
Engineering Services Branch

- In December, 1999, 6719 wells reported production
- 31 % were horizontal wells

- In December, 1999, horizontal wells accounted for 31 % of the producing wells in southeast Saskatchewan and 55 % of the monthly production volume



- Monthly oil production from horizontal wells reached a peak of 3.25 million barrels in December, 1997
- In December, 1999, 2077 wells reported production of 2.6 million barrels



- A sample of over 1000 horizontal wells and 1000 vertical wells drilled between 1989 and 1996 was used to estimate the typical production profile for each type of well
- Although there is a wide range of productivity within the basin, the ultimate recovery of a typical horizontal well is 2 to 3 times that of a typical vertical well

F

The Petroleum Technology Research Centre in Regina - Research with a Bottomline

Roland Moberg
Petroleum Technology Research Centre

The Petroleum Technology Research Centre in Regina - research with a bottomline

Eighth Williston Basin Horizontal Well Workshop

May 8, 2000

Outline of presentation

- PTRC - what is it?
- PTRC - what do we offer?
- What is research?
- The research process
- Attributes of successful research organizations
- Keys to success
- History of research in the oil and gas industry
- The challenges facing a research organization
- Key challenges in the Saskatchewan oilpatch
- Key research areas
- Key PTRC strategies
- Barriers to technology innovation/implementation
- Conclusions

PTRC - what is it?

- A new non-profit petroleum R&D corporation
- A collaborative initiative between NRCan, Saskatchewan Energy and Mines, the University of Regina and the Saskatchewan Research Council
- Will occupy a new state of the art research facility at the University of Regina Research Park on July 1, 2000
- Base level of funding secured for first 5 years of operation

PTRC - what do we offer?

- SRC brings 15 years of experience into research to improve the performance of Saskatchewan reservoirs
- Interdisciplinary research involving University of Regina scientists from petroleum, chemical and environmental engineering, computer science, physics and earth sciences
- Full range of technology development activities from basic to applied R&D to demonstration in the laboratory and in the field
- High financial leverage for industrial customers
- Both joint industry and single client projects

What is research?

- "Diligent and systematic inquiry or investigation into a subject in order to discover or revise facts, theories, applications". Webster's Dictionary
- "Attempt to discover new facts, knowledge, and information, to develop new interpretations of facts, knowledge or information, or to discover new means of applying existing knowledge". Canadian Foundation for Innovation.

The research process - key steps

- Generate idea or hypothesis
- Scope out technical and economic feasibility
- Physical modeling or prototype
- Numerical modeling
- Economic analysis
- Field pilot
- Commercial application

Attributes of successful research organizations

- Management knows what research and other talents it needs
- Employees are passionate about their work
- Needs of customers drive the organization and its research programs
- Employees and customers share management's vision, values and goals
- The portfolio of programs represents the right research, at the right time and the right investment
- Research projects embody excellent science, involve the right people, are on track and within budget
- Research projects leverage external resources
- Organizational knowledge is systematically captured and turned into needed work tools
- The organization is widely known and respected

Keys to success

- Being relevant to industry
- Doing high quality research
- Being responsive to customers
- Delivering on promises
- Customers successful in implementing technologies

History of research in the oil and gas industry

- Proprietary research by multi-nationals
- Service companies playing an increasingly important role
- Research into affordable heavy oil eor most successful
- Collaborative research initiatives more common today
- Research organizations being rationalized
- Many field trials have been ill conceived
- Application of technologies much more important than ownership today

The challenges facing a research organization

- Short term focus of customers
- Long-term nature of most research
- Long-term funding is difficult to secure
- Focus in a few areas versus doing research in many areas
- How to achieve critical mass
- How to remain at the leading edge
- How to stay in touch with the real customers

Key challenges in the Saskatchewan oilpatch

- Mature aging oil fields
- Marginal reserves with generally low recovery factors
- Higher cost structure
- Many EOR schemes have failed
- Waterhandling

Key research areas

- Miscible or near miscible recovery of light oil with carbon dioxide
- Steam flooding and horizontal wells
- Conventional heavy oil EOR
- Emulsion EOR
- Water handling and emulsion/sand/slop treatment
- Multi-phase flow in pipelines and wellbores
- Environmental

Key PTRC strategies

- Become the one-stop shop for intelligence about the Saskatchewan oilpatch
- Develop research programs jointly with industry
- Gain access to field pilots for researchers
- Terminate projects that do not pan out
- Developing a special initiative aimed at SMEs

Barriers to technology innovation/implementation

- Low-tech approach favoured by many companies
- Initial costs of new technology usually high
- High risk of failure
- Lack of expertise
- Technology development and transfer a complex process
- Many EOR processes are high cost, complex and manpower intensive

Conclusions

- We are open for business now
- We have strong industry representation on Board and Technical Advisory Committee
- We want to work on problems that are important to you
- Standing invitation to visit us at our new facility or website ptrc.ca

G

Greenhouse Gas Policy

How will it affect the oil industry?

David Hanly
Saskatchewan Energy and Mines

Eighth International Williston Basin
Horizontal Well Workshop
May 7-9, 2000

Greenhouse Gas Policy

How will it affect the oil industry?

Outline of Speaking Notes and
Copy of Charts

David Hanly
Senior Energy Economist
Saskatchewan Energy and Mines

Disclaimer: Discussion contained in this presentation is not the official view or recommended policy of the government of Saskatchewan.

Is Global Climate Change a real problem?

- Issue is surrounded by uncertainty.

Two things are certain

- Preliminary government policy has already been developed to address climate change.

- More policy is under development to deal with emissions of greenhouse gases from combustion of fossil fuels.

Policy Developments in Canada

- Extensive consultation with industry and other groups.

- Petroleum sector has released a foundation paper available at http://www.nccp.ca/html/index.htm

Policy Developments in United States

- Promotion of clean energy $US1B 1999/2000

- Energy efficiency
  (see http://www.eren.doe.gov/EE/industrial.html)

The Kyoto Accord (December 1997)

- The agreement has different targets for each country

	Actual 1997 emissions relative to 1990 (% change relative to 1990)	Kyoto Emissions Target (% change relative to 1990)
United States	+10.3	-7
Canada	+12.5	-6
Australia	+9.5	+8
United Kingdom	-9.4	-8
Ukraine	-49.6	0

Potential Timing of Greenhouse Gas Policy

Phase 1 (2000-2002?) - pre-ratification of Kyoto

- Voluntary actions by individuals and businesses to reduce greenhouse gas emissions.
- Government information and demonstration programs.
- Government support of research and development.

Phase 2 (2002?-2008) - post-ratification

- Need to get down to Kyoto target by Kyoto compliance period of 2008-2012.

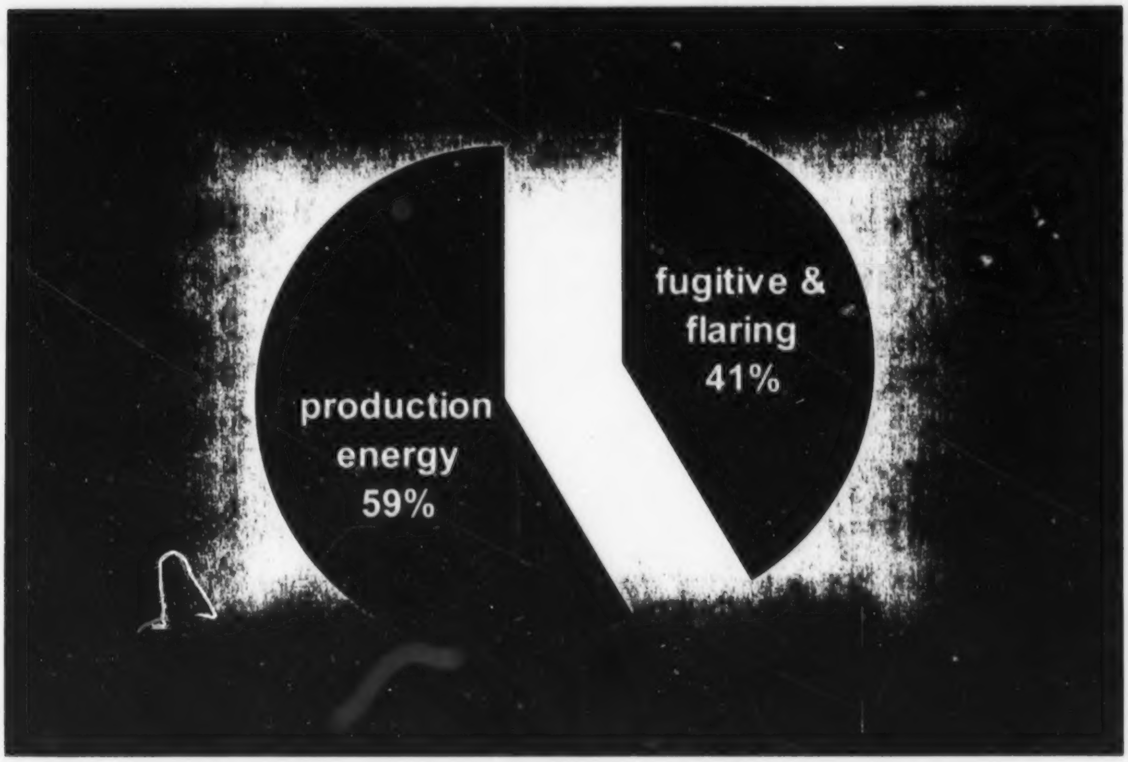
Phase 3 (2008-2012) - Kyoto Commitment Period

- Actual emissions during this period determine if Kyoto target is met.
- Kyoto targets are not expected to stop climate change, only to slow down rate of change.

Direct Emissions of Oil and Gas Industry

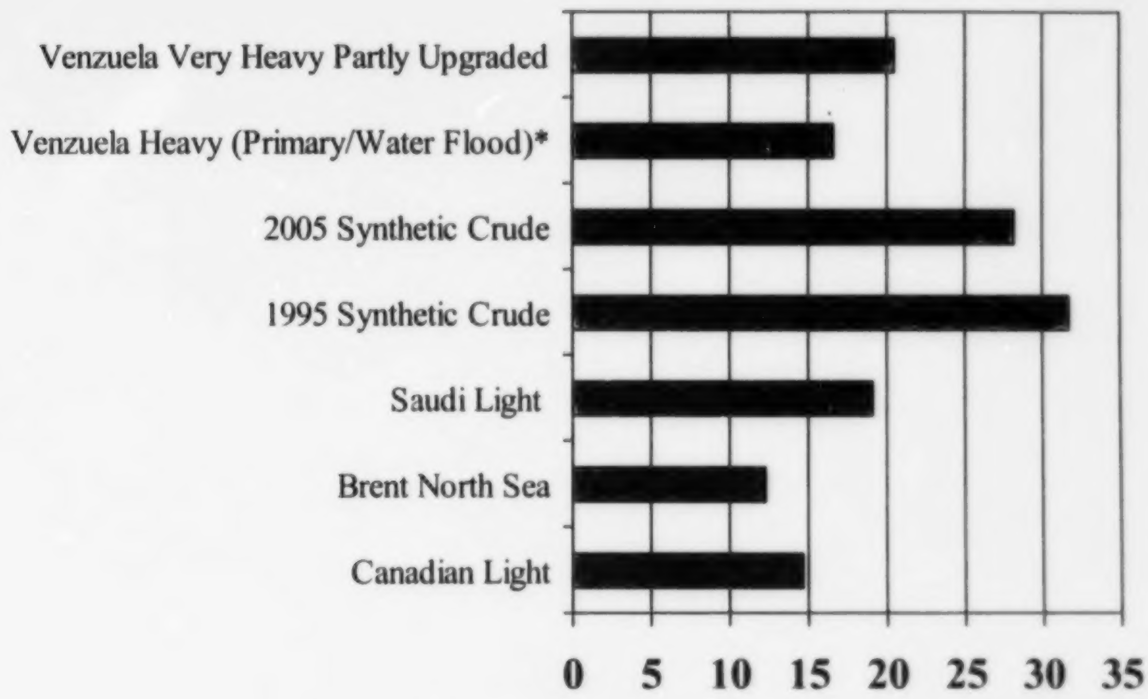
- 18% of total national GHG emissions in Canada (upstream alone 12% of national GHG emissions)

- 2% (fugitive and flaring only) of total national emissions in the U.S.A.



Source: Canada's Greenhouse Gas Inventory, 1995, Environment Canada and **Oil and Natural Gas Industry Foundation Paper**

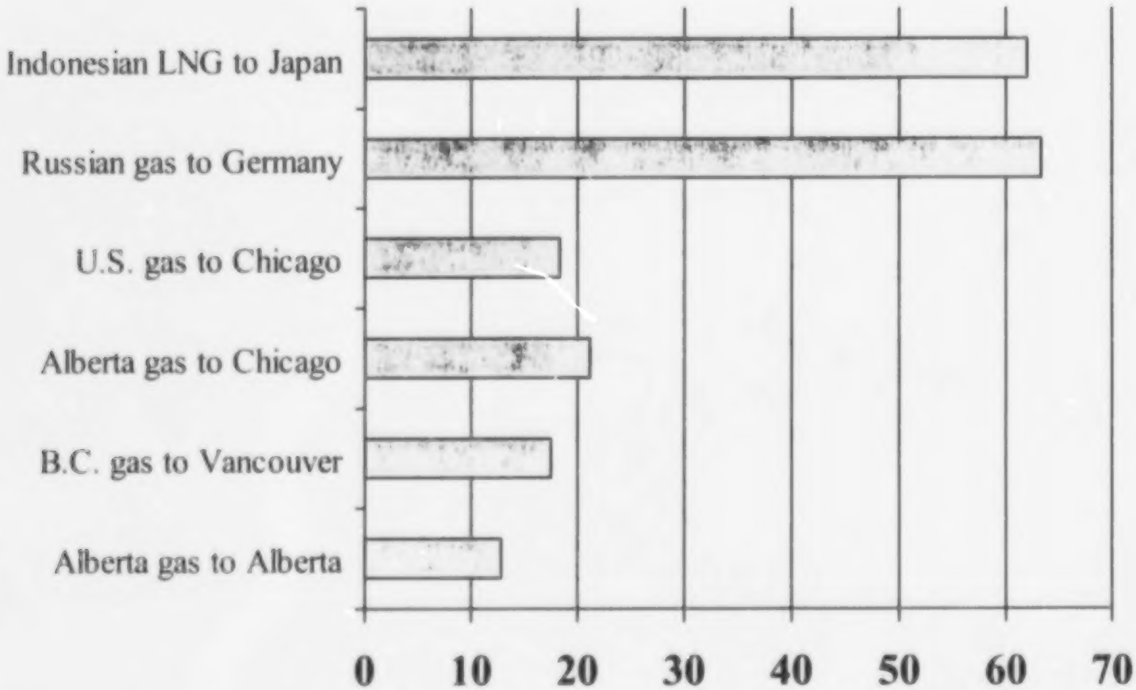
GHG Emissions in Production, Transportation and Refining of Oil delivered to mid North America as a proportion of End-use emissions (%)



* - may be too low

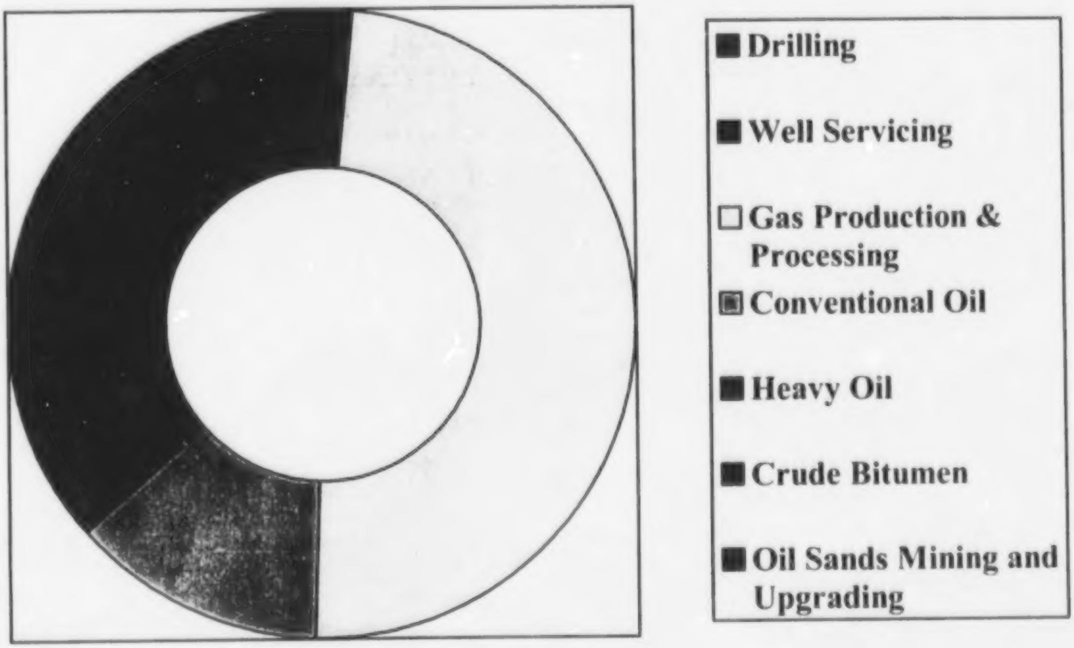
Source: Data in table C-1 from **Oil and Natural Gas Industry Foundation Paper,** Canadian National Climate Change Secretariat

GHG Emissions in Production, Transportation and Storage of Natural Gas as a proportion of End-use emissions (%)



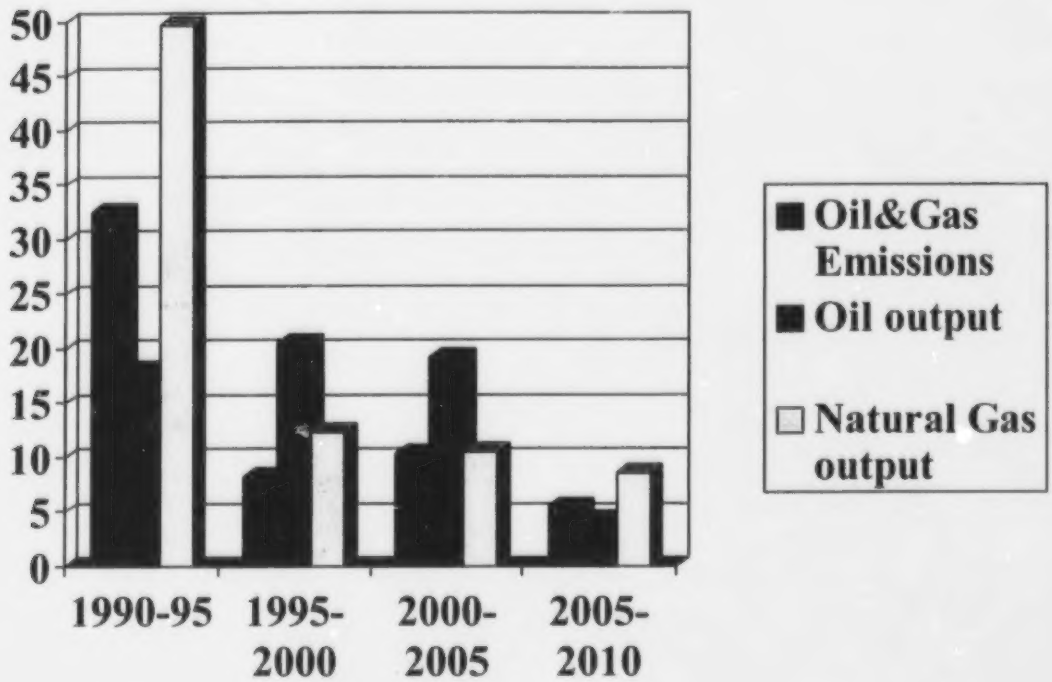
Source: Data in table C-2 from **Oil and Natural Gas Industry Foundation Paper,** Canadian National Climate Change Secretariat

Direct GHG emission level by activity in Canadian Upstream Oil and Gas



Source: Data in table G-1 from **Oil and Natural Gas Industry Foundation Paper,** Canadian National Climate Change Secretariat

Actual and Forecast Growth in Canadian Upstream Emissions and Oil and Natural Gas Production



Source: Canada's Emission Outlook: An Update, Natural Resources Canada

- Forecasted reductions in emission intensity over the period of 1995-2010 of 5% for oil and 13% for natural gas (**Oil and Natural Gas Industry Foundation Paper).**

Opportunities and Challenges for Williston Basin Producers from GHG policy

- Use of CO2 for enhanced oil recovery

- Demand for natural gas

- Conventional or turbine generation of electricity from captured natural gas

- Impacts on oil prices

Government perspective on the impact of climate change policy with respect to the oil and gas industry

- the industry is of major importance in creating jobs and high incomes in the local economy

- the oil and gas industry is an important contributor to government tax revenue

- governments will continue to seek industry advice on what policies make sense

H

RotaFlex Long Stroke Pumping Units

Darren Wiltse
Weatherford Artificial Lift Systems

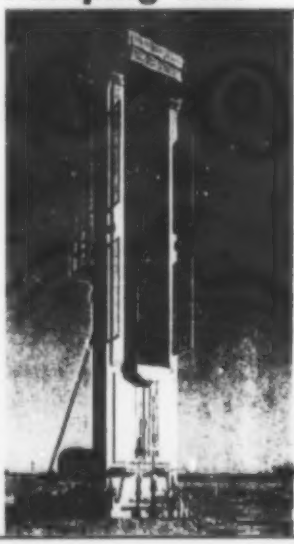
Weatherford

RotaFlex® Long Stroke Pumping Units

ARTIFICIAL LIFT SYSTEMS

RotaFlex® Long Stroke Pumping Unit

Weatherford

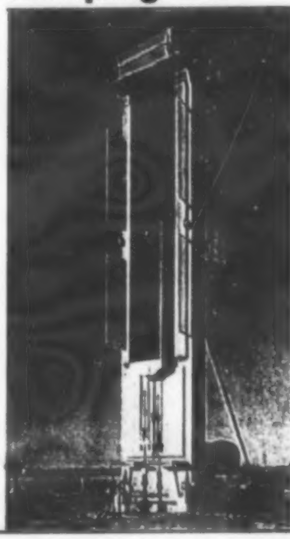


- First Successful Long Stroke Pumping unit in 40 Years
- 24 Foot Stroke Length for Sucker Rod Pumps
- High Production Capability
- High System Efficiency and Cost Effectiveness for Deep, Troublesome and High-Volume Wells
- Use in Place of Electic Submersible or Hydraulic Subsurface Pumps

ARTIFICIAL LIFT SYSTEMS

RotaFlex® Long Stroke Pumping Unit

Weatherford

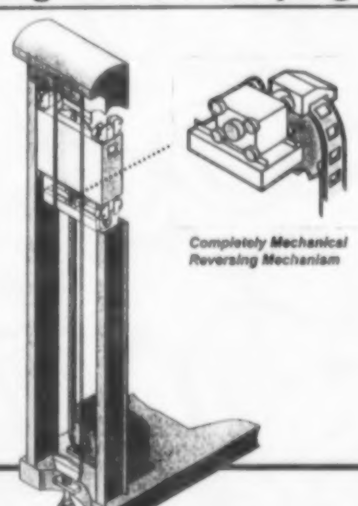


- Improved Subsurface Equipment Life
- 40 to 60% Reduction in Rod Reversals = Greater Rod Life
- 20 to 50% Reduction in Electrical Costs
- Lower Peak Power Demand
- Helps in Eliminating Gas Lock Problems
- 100% Mechanical Design - Uncomplicated with Low Maintenance

ARTIFICIAL LIFT SYSTEMS

Features of the RotaFlex® Long Stroke Pumping Unit

Weatherford



- Innovative Mechanical Design
- Chain Driven with Conventional API-type Gearbox

ARTIFICIAL LIFT SYSTEMS

Features of the RotaFlex® Long Stroke Pumping Unit

Weatherford

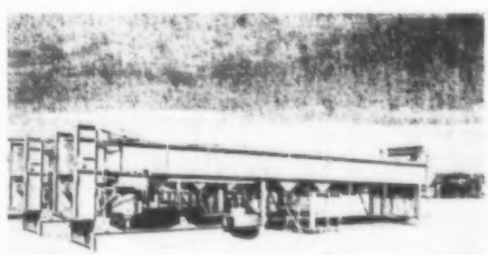
- Direct Counterweight Connection to Well Load
- Shock Absorbing Load Belt

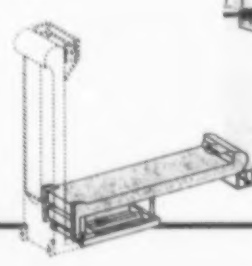
ARTIFICIAL LIFT SYSTEMS

Features of the RotaFlex® Long Stroke Pumping Unit

Weatherford

- Can Be Folded Over for Shipment As A Single Piece



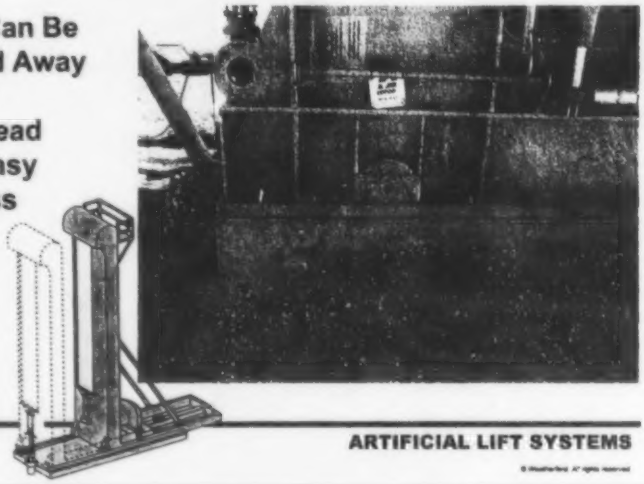


ARTIFICIAL LIFT SYSTEMS

Features of the RotaFlex® Long Stroke Pumping Unit

Weatherford

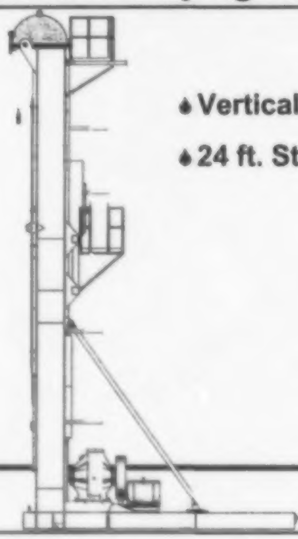
- Unit Can Be Rolled Away From Wellhead For Easy Access



ARTIFICIAL LIFT SYSTEMS

Features of the RotaFlex® Long Stroke Pumping Unit

Weatherford



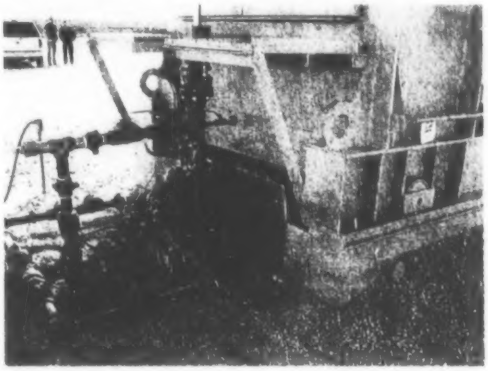
- Vertical Unit
- 24 ft. Stroke Length

ARTIFICIAL LIFT SYSTEMS

Features of the RotaFlex® Long Stroke Pumping Unit

Weatherford

- Base and Unit Mount Close to Wellhead
- Custom Base Design for RotaFlex Unit
- Platform for Counterbalance Installation

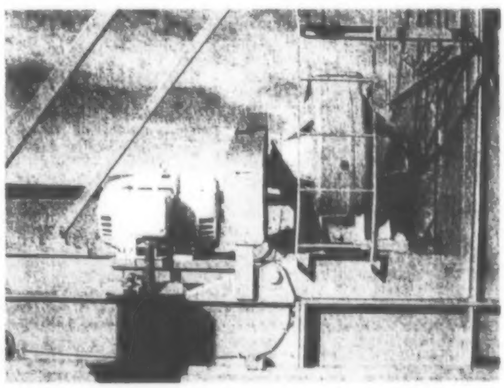


ARTIFICIAL LIFT SYSTEMS

Features of the RotaFlex® Long Stroke Pumping Unit

Weatherford

- Hinged Belt Guard for Easy Access
- Unit and Motor Sheaves at Ground Level
- Strokes Per Minute Range of 1 - 4.5

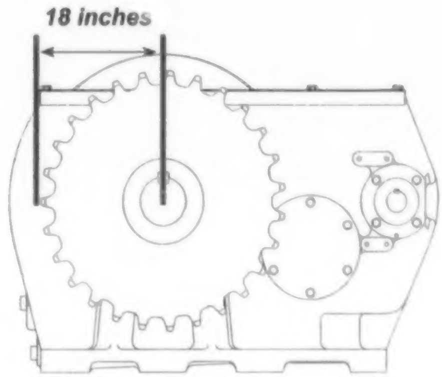


ARTIFICIAL LIFT SYSTEMS

Features of the RotaFlex® Long Stroke Pumping Unit

Weatherford

- Short Torque Arm Results in Smaller Gear Reducers
- Improved System Efficiency with Smaller Gear Reducer



ARTIFICIAL LIFT SYSTEMS

Features of the RotaFlex® Long Stroke Pumping Unit

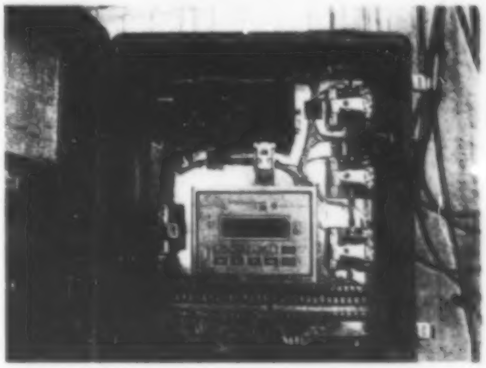
Weatherford

- Manual and Automatic Braking System
- Easy Access for Brake Pad Adjustment
- Beam Mounted Vibration Switch

ARTIFICIAL LIFT SYSTEMS

RotaFlex® Speed Sentry

- Displays Operating SPM
- Underspeed and Overspeed Shutdowns Based on SPM
- Automatically Engages Emergency Brake System After Speed Violation



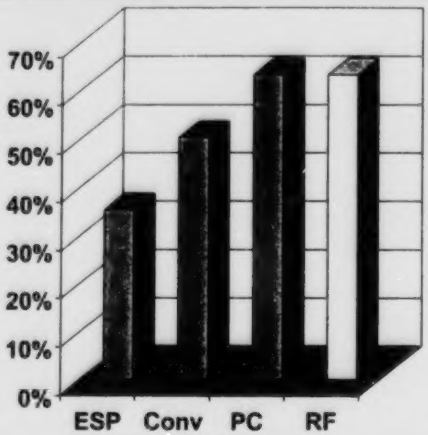
ARTIFICIAL LIFT SYSTEMS

Vector Drive Option

- Adjustable SPM Settings at Constant Speed
- Increase Maximum Average SPM From 4.5 - 5.2 with Two-Speed Operation
- Adjustable Upstroke and Downstroke SPM Settings for Heavier Crudes

ARTIFICIAL LIFT SYSTEMS

System Efficiency Comparison



- Highly Efficient Pumping System

ARTIFICIAL LIFT SYSTEMS

RotaFlex® Unit Specifications

	800	900	1100
Structure Rating (lbs)	25,600	36,000	50,000
Stroke Length (in)	288	288	306
Gearbox Size (in/ lbs)	228,000	320,000	320,000
Unit Shipping Weight (lbs)	46,000	46,000	56,000
Base Shipping Weight (lbs)	29,000	29,000	29,000
Minimum Counterweight (lbs)	9,200	9,200	14,000
Maximum Free Weight (lbs)	9,800	17,800	16,000
Maximum Counterweight (lbs)	19,000	27,000	30,000

ARTIFICIAL LIFT SYSTEMS

RotaFlex®
Production Capabilities

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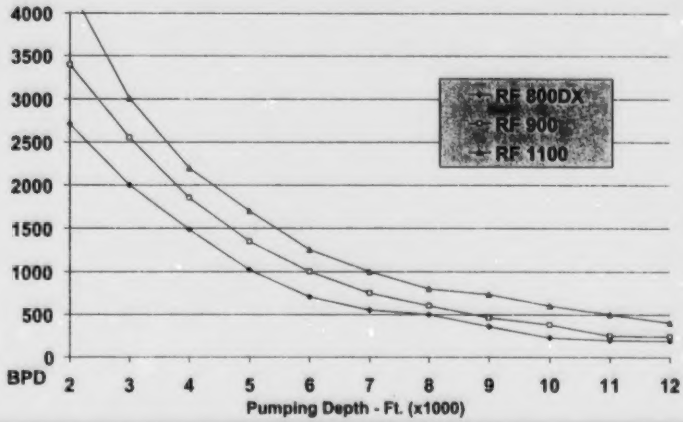

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System Efficiency

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- N_{sys} = HHP/IHP
  - *HHP = hydraulic horsepower for fluid lifting*
  - *IHP = electric horsepower input*

ARTIFICIAL LIFT SYSTEMS

System Efficiency - cont'd

Weatherford

- $N_{sys} = (N_{lift})(N_{mech})(N_{mot})/CLF$
  - N_{lift} = lifting efficiency
    - hydraulic horsepower/polished rod horsepower
    - energy losses from rod pump, sucker rod and flow losses
  - N_{mech} = mechanical efficiency of pumping unit
    - polished rod horsepower/mechanical power
    - energy losses from friction within stuffing box, bearings and gear reducer

ARTIFICIAL LIFT SYSTEMS

System Efficiency - cont'd

Weatherford

- N_{mot} = overall efficiency of electric motor
  - heavier the load the more efficient
- CLF = cyclic load factor
  - fluctuating loads ⟶ higher CLF ⟶ larger elec. motor

ARTIFICIAL LIFT SYSTEMS

Weatherford

* * * RODSTAR 2.35 for Windows * * *

Company: Example
Well: Conventional
Disk file: CONVENT1.RST
Comment:

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Tel: (714) 526-8878

Page 1/1
User: DJW
Date: 14-Apr-00

INPUT DATA

Target prod. (BFPD): 600 | Fluid level
Run time (hrs/day): 24.0 | (ft from surface): 7000
Tubing pres. (psi): 90.0 | (ft over pump): 0
Casing pres. (psi): 90.0 | Stuf.box fr. (lbs): 100

Fluid properties

Water cut: 90%
Water sp. gravity: 1.03
Oil API gravity: 35.0
Fluid sp. gravity: 1.012

Motor & power meter

Power meter: Detent
Electr. cost: 0.06/KWH
Type: NEMA D

Unit: Ampscot Conventional: With A120 Cranks

API size: C-912-365-144 (unit ID: [illegible])
Crank hole #1 (out of 3)
Calculated stroke length (in): 145.3
Rotation with well to right: CCW
Max. CB moment (M in-lbs): Unknown
Structural unbalance (lbs): -200
Crank offset angle (deg): 0.0

Tubing and pump information

Tubing O.D. (in): 2.875 | Rod-tub. frict.: 0.37(up)
Tubing I.D. (in): 2.441 | 0.37(dn)

Pump depth (ft): 7000.0 | Tub.anch.depth (ft): 7000
Pump condition: Full | Pump load adj. (lbs): 0
Pump type: Tubing | Pump vol. efficiency: 88%
Plunger size (in): 2.25 | Pump friction (lbs): 200

CALCULATED RESULTS

Peak pol. rod load (lbs): 33992 | Balanced minimum
Min. pol. rod load (lbs): 8199 | required motor HP: 87.4
System eff. (Motor->Pump): 38% | Polished rod HP: 49.9
Fluid load on pump (lbs): 12106 | Unit struct. loading: 93%
Buoyant rod weight (lbs): 13579 | W/Wo: 0.271, Fo/SKr: 0.362
Production rate (BFPD): 603 | Strokes per minute: 10.35

Required prime mover size (speed var. not included)	BALANCED (Min Ener)	BALANCED (Min Torq)
NEMA D motor:	125 HP	125 HP
Single/double cyl. engine:	100 HP	100 HP
Multicylinder engine:	125 HP	125 HP

Torque analysis and electricity consumption	BALANCED (Min Ener)	BALANCED (Min Torq)
Peak g'box torq. (M in-lbs):	1285	1093
Gearbox loading:	141%	120%
Cyclic load factor:	1.76	1.76
Max. CB moment (M in-lbs):	1304.86	1500.94
Counterbalance effect (lbs):	19184	22097
Daily electr. use (KWH/day):	1483	1488
Monthly electric bill:	$2678	$2723
Electr. cost per bbl. fluid:	$0.146	$0.148
Electr. cost per bbl. oil:	$1.454	$1.481

Tubing, pump and plunger calculations

Tubing stretch (in):	0.0
Prod. loss due to tubing stretch (BFPD):	0
Gross pump stroke (in):	116
Pump spacing (in. from bottom):	21.0
Minimum pump length (ft):	23.0
Recommended plunger length (ft):	5.0

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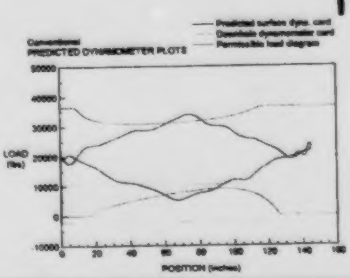
Rod string design (rod tapers calculated)

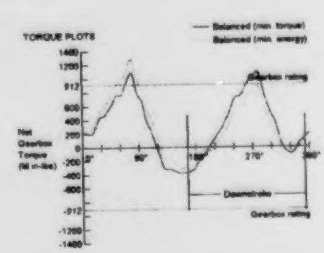
Diameter (inches)	Rod Grade	Length (ft)	Tensile Strength (psi)
16/16	Corod-SE Ultr	1093	N/A
15/16	Corod-SE Ultr	1229	N/A
14/16	Corod-SE Ultr	4678	N/A

NOTE: Stress calculations include buoyancy effects.

Rod string stress analysis (service factor: [illegible])

Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	Stress Calc. Method
97%	43153	6747	4813	API MG, T/3
98%	42596	5476	4023	API MG, T/3
97%	41914	4819	-3680	API MG, T/3





ARTIFICIAL LIFT SYSTEMS

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* * * RODSTAR 2.33 for Windows * * *

Company: Example
Well: Rotaflex
Disk file: CONVENT1.RST
Comment:

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Tel: (714) 526-8878

Page 1/1
User: DJW
Date: 14-Apr-00

INPUT DATA

Target prod. (BFPD): 600
Run time (hrs/day): 24.0
Tubing pres. (psi): 50.0
Casing pres. (psi): 50.0

Fluid level
(ft from surface): 7000
(ft over pump): 0
Stuf.box fr. (lbs): 100

Fluid properties

Water cut: 90%
Water sp. gravity: 1.03
Oil API gravity: 38.0
Fluid sp. gravity: 1.012

Motor & power meter

Power meter: Detent
Electr. cost: $.06/KWH
Type: NEMA D

Unit: Rotaflex (900)

API size: R-320-360-288 (unit ID: R1)
Crank hole #1 (out of 1)
Calculated stroke length (in): 290.7
Rotation with well to right: CCW
Max. CB weight (M lbs): Unknown

Tubing and pump information

Tubing O.D. (in): 2.875
Tubing I.D. (in): 2.441
Rod-tub. frict.: 0.57(up) 0.57(dn)

Pump depth (ft): 7000.0
Pump condition: Full
Pump type: Tubing
Plunger size (in): 2.25
Tub.anch.depth (ft): 7000
Pump load adj. (lbs): 0
Pump vol. efficiency: 85%
Pump friction (lbs): 200

CALCULATED RESULTS

Peak pol. rod load (lbs): 29888
Min. pol. rod load (lbs): 9670
System eff. (Motor->Pump): 58%
Fluid load on pump (lbs): 12196
Buoyant rod weight (lbs): 13481
Production rate (BFPD): 596

Balanced minimum required motor HP: 53.9
Polished rod HP: 46.7
Unit struct. loading: 83%
N/No': 0.118, Fo/SKr: 0.181
Strokes per minute: 4.5

Required prime mover size (speed var. not included)	BALANCED (Min Ener)	BALANCED (Min Torq)
NEMA D motor:	75 HP	60 HP
Single/double cyl. engine:	60 HP	60 HP
Multicylinder engine:	75 HP	60 HP

Torque analysis and electricity consumption	BALANCED (Min Ener)	BALANCED (Min Torq)
Peak g'box torq. (M in-lbs):	186	176
Gearbox loading:	61%	58%
Cyclic load factor:	1.1	1.09
Counterbalance weight (M lbs):	18.55	19.00
Daily electr. use (KWH/day):	946	958
Monthly electric bill:	$1727	$1754
Electr. cost per bbl. fluid:	$0.095	$0.096
Electr. cost per bbl. oil:	$0.950	$0.964

Tubing, pump and plunger calculations

Tubing stretch (in):	0.0
Prod. loss due to tubing stretch (BFPD):	0
Gross pump stroke (in):	264
Pump spacing (in. from bottom):	35.2
Minimum pump length (ft):	35.0
Recommended plunger length (ft):	5.0

ARTIFICIAL LIFT SYSTEMS

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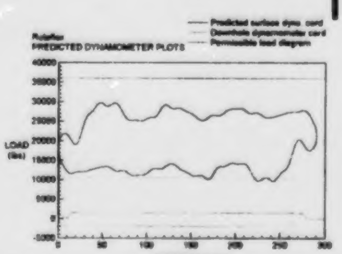
Rod string design

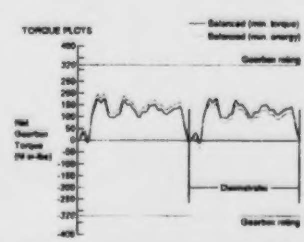
Diameter (inches)	Rod Grade	Length (ft)	Tensile Strength (psi)
16/16	Corod-SE Ultr	1093	N/A
15/16	Corod-SE Ultr	1229	N/A
14/16	Corod-SE Ultr	4678	N/A

Rod string stress analysis (service factor: 0.9)

Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	Stress Calc. Method
68%	37673	12440	6803	API MD, T/3
71%	38649	10015	6988	API MD, T/3
74%	38527	8022	-3680	API MD, T/3

NOTE: Stress calculations include buoyancy effects.





ARTIFICIAL LIFT SYSTEMS

Rotaflex Applications

Weatherford

- 750 units installed throughout the world
- Light, Medium, Heavy Oil
- Vertical, Directional, Horizontal

- SAGD - 17 units Marathon

ARTIFICIAL LIFT SYSTEMS

Slim Hole Rotary Steerable Short Radius Horizontal Drilling System

J. David LaPrade
Torch Drilling Services L.L.C.

SLIM HOLE ROTARY STEERABLE SHORT RADIUS HORIZONTAL DRILLING SYSTEM

J. David LaPrade

TORCH DRILLING SERVICES L.L.C.

Eighth International Williston Basin Horizontal Well Workshop
Bismarck, North Dakota
May 7-9, 2000

Introduction

During the past decade, the oil and gas industry witnessed a steady increase in the use of horizontal drilling to enhance well productivity. This trend will no doubt continue well into the 21st century as operators become increasingly aware of the benefits associated with drilling horizontally. As the database of horizontal projects has grown, operators have developed a better understanding of how and where horizontal wells should be utilized and which technology is best for a given application.

Economics will, in most cases, dictate the technology to be used. The implementation of laterals in mature fields requires substantial cost reductions over the methods most often used for drilling horizontal wells. Because of this, the use of short radius horizontal re-entry and completion technology to re-activate and rejuvenate existing fields is growing rapidly.

Short radius horizontals can be an alternative completion procedure for new wells or can be used for the re-completion of existing wells. Initiating a lateral from an existing wellbore is often much cheaper than drilling a new well to kickoff point. In either case, the horizontal costs must be kept low to achieve acceptable economics.

This paper describes a short radius lateral drilling system developed by Amoco Corporation that can offer operators substantial cost savings over conventional mud motor technology.

History of Tool Development

The need for a reliable reduced-cost drilling system that uses the equipment and cost structures associated with workover and repair services provided the impetus for the development of this technology.

In 1989, Amoco initiated a project to develop a short radius lateral drilling system. The development criteria consisted of four main objectives:

(1) develop a system low in cost to manufacture, repair and operate;
(2) develop a system that will drill a predictable and consistent radius of curvature in a desired direction,

(3) develop a system capable of operating from a service rig using a power swivel; and
(4) develop a system capable of working inside 4.5" casing.

Following development of the prototype tools, more than 200 test wells were drilled at Amoco's Catoosa Test Facility near Tulsa, Oklahoma. Following testing, the technology was taken to the field where it was used to drill several wells at Amoco's Levelland Unit. These initial test wells proved the basic capability to install lateral drain holes at a reasonable cost with a top drive power swivel and workover rig.

The system, which has become known as the "Rotary Steerable System", has been tested, developed and improved to the point where it is a successful and commercially viable technology. Since the first quarter of 1995, more than 100 wells have been drilled with the Rotary Steerable System.

The "Rotary Steerable System"

The system is purely mechanical. There are no mud motors or expensive electronics downhole. In comparison to typical mud motor systems, overall total well costs can be considerably lower. Simple parts maintenance of the downhole assemblies translates into quick on-site repair time eliminating costly standby time charges associated with shop repairs. Spare parts are readily available and cost pennies on the dollar compared to other systems. Inspection and repair charges are greatly reduced and lost-in-hole liability is minimal.

In this horizontal drilling system, bit rotation is derived from the power swivel with continuous pipe rotation throughout the curve and lateral drilling process.

The Rotary Steerable System is capable of drilling three hole sizes:
(1) 3.875" to work inside 4.5" casing;
(2) 4.5" to work inside 5.5" casing; and
(3) 6.125" to work inside 7" casing or larger.

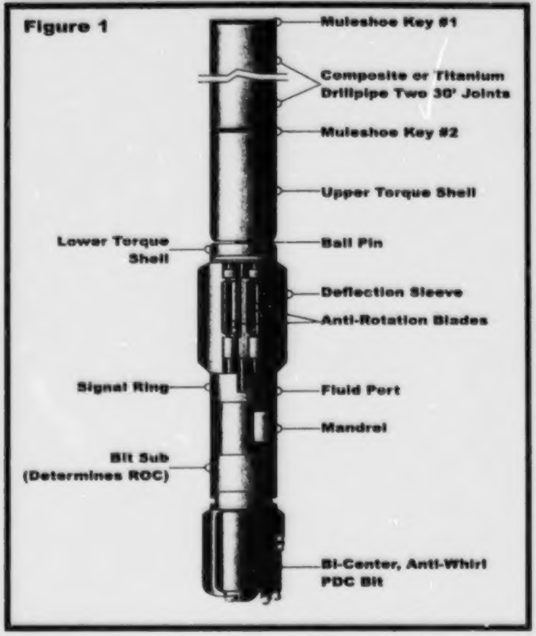
Radius of curvature ("ROC") generally ranges from 30 feet to 100 feet; larger radii can be drilled when required. Lateral departures have typically been 300 feet to 1,000 feet. While longer laterals are possible, the most frequently drilled wellpath has combined a radius of 35 feet with a 500 foot lateral.

Multiple laterals can be drilled in opposing directions or in the same direction, landing at the same true vertical depth ("TVD") or at varying TVD's. Compatibility with any circulating medium including water or mud, foam, air mist or air allows for a variety of applications.

The Curve Drilling Assembly ("CDA") (Figure 1) is very simple in design. Key features of the CDA include an Amoco-patented anti-whirl, bi-center PDC bit, bit sub, signal ring, non-rotating deflection sleeve, lower torque shell, ball pin and upper torque shell.

Design of the anti-whirl bit provides for a consistent and reliable angle build. Directional control is a result of stabilizing the bit to continually point along a curve path. Cutters are positioned so that they direct a lateral force to a smooth pad on the gauge of the bit. This pad contacts the borehole and acts as a bearing by transmitting a restoring force to the bit. This force rotates with the bit and continually pushes the smooth or bearing side of the bit against the borehole wall. This design minimizes the side cutting action that is typically observed with PDC bits and results in a consistent wellbore diameter.

Figure 1



The deflection sleeve (Figure 2) houses blades which, during right hand rotation, engage the wellbore to maintain toolface direction. Left hand rotation allows the driller to reposition the toolface in the event of slippage.

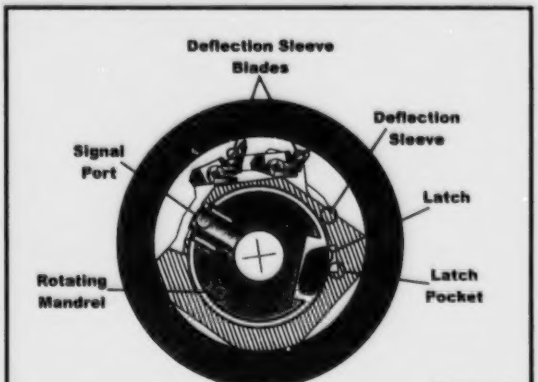


Figure 2

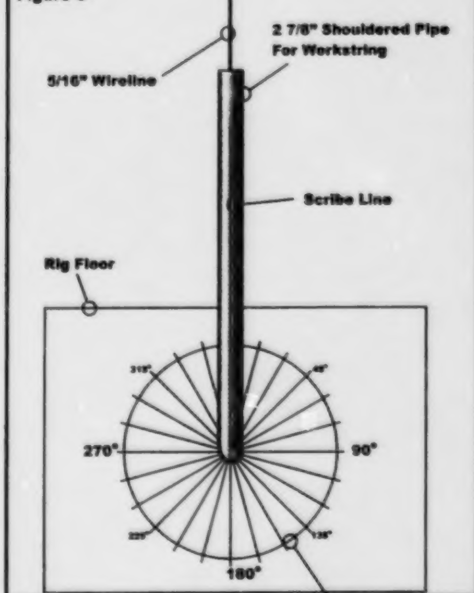
The CDA drills a curved path by continually pointing the bit along a tangent to the curved path. Contact points on the bit and the wear pad at the base of the deflection sleeve control the bit tilt. Tool design tilt allows the CDA to run smoothly, drill a hole uniform in diameter and negate the effects of varying lithology. The desired radius of curvature is obtained by utilizing a bit sub to alter the distance between the two contact points.

Initial toolface positioning to the target azimuth is established by gyro orientation. A protractor plate is used on the rig floor to orient toolface and reference target direction. A scribe line is placed on the workstring coinciding with target direction on the protractor plate (Figure 3). Once oriented to the desired direction, the toolface is monitored by pump pressure signals at surface. These signals are monitored throughout the curve drilling process to maintain directional control.

Lateral drilling is strictly a rotary process. The lateral assembly consists of an anti-whirl bit, two stabilizers and two articulated subs connected to a flexible drill string of composite, titanium or steel pipe. The lateral

assembly is essentially a point and shoot technology -- the bit goes where it is pointed. Over a 500 lateral, the azimuth change is 3 degrees or less. At the present time, there are two assemblies. The "Gentle Riser" is engineered for a build rate of approximately 10 degrees per 100 feet. The "Straight Shooter" is for maintaining inclination and produces near neutral responses of –2 to +2 degrees per 100 feet.

Figure 3



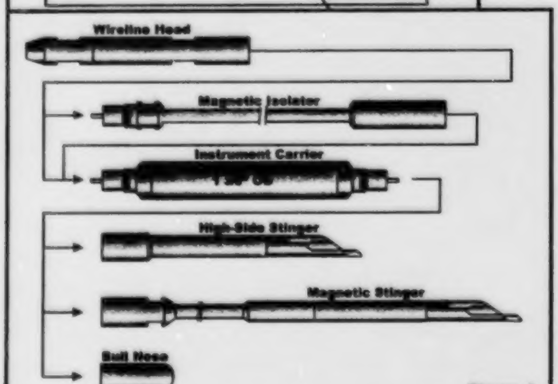


Figure 4

Surveying is done with a tri-axial steering tool probe (Figure 4). The probe contains specially designed miniaturized instrumentation that can negotiate doglegs approaching 2 degrees per foot inside 1.5" ID pipe. Electronics consist of flux-gate magnetometers and accelerometers. All data is real time and transmitted to surface via 5/16" single conductor wireline. Survey data includes inclination, azimuth, magnetic field, gravity toolface, magnetic toolface and temperature. Following a drilled segment, probes are run in the hole and if needed, the mud pump is engaged to deliver the probe to bottom. Because of the high build rates to drill a 30 foot to 60 foot radius and the small margin of error in hitting TVD targets within ± 2 feet and at the desired angle, surveys are pulled in 2 foot stations. Typically, 2-3 surveys are run in the curve drilling process. Survey data is then used to project inclination at the bit. Probes are tripped out before drilling resumes.

In the lateral, surveys are usually run every 100 feet. However, this may vary depending on dip rates, target thickness, rock hardness and knowledge of the formation being drilled.

Equipment Requirements

Minimal surface equipment requirements give the Rotary Steerable System an advantage over conventional mud motor technology. The rig is usually a standard service/workover rig capable of pulling double stands with a hook load capacity of 120,000 lbs. and equipped with pipe racks and catwalk. Handling tools should include open faced tubing tongs with torque gauge, 2-7/8" slip type elevators, an accurate weight indicator, a mud pump gauge on the rig floor and an adequate supply of spare parts.

Other equipment should include a 500 bbl frac tank for water storage, a 100 bbl mud mixing pit, a 200-400 bbl working pit, a lined sump pit, a high frequency linear shale shaker, a tri-plex pump, a standard workover BOP stack and accumulator, a power swivel, a workstring (2-7/8" PH-6, AOH or DSS), 3-4 light plants and a 60 KW generator. In the event hydrogen sulfide is present, a safety trailer containing air packs and fire extinguishers should be on location.

The power swivel is a key piece of the surface equipment. A remote control panel with electric controls over air or hydraulics and a back brake system is required. The remote controls should have an accurate torque gauge. Torsional control (both left and right) is critical. The swivel must respond immediately to the remote controls.

The exact equipment package may vary depending on formation pressure, the drilling medium used, location restrictions and operator and/or state requirements.

Planning for a Re-entry

Spacing requirements in many mature fields may limit horizontal displacements to 1,000 feet or less. Short radius wells allow for maximum reservoir exposure. There are hundreds of fields and many thousand wellbores that are potential re-entry candidates in the U.S. alone.

One key advantage associated with working within a producing field and existing wellbores is access to geological maps, core data, reservoir characteristics, well logs, wellbore schematics and well completion reports. The more complete the information, the better the chance of an operator achieving an economic success.

When selecting a target interval and screening a wellbore for suitability as a re-entry candidate, consideration should be given to overlying formation properties. Many times, problem formations such as reactive shales, washouts and gas or water zones exist above the zone of interest. While the application of short radius drilling can often allow the operator to avoid drilling through these potential problems, consideration should be given early in the planning process to determine how they can be avoided. In addition, high concentrations of pyrite, anhydrite or chert can drastically affect penetration rates and should be avoided when possible.

The radius of curvature, which may range from 30 feet to 100 feet, is determined by up hole conditions, the desired lateral displacement, thickness of the target interval and completion requirements. The kickoff point is determined by the radius of curvature, desired landing depth of the curve and location of casing collars and perforations.

Once all data is reviewed, a proposed wellpath is chosen, the kickoff point is selected and a wellbore preparation schematic is prepared.

The planning process is not complete without careful review of the drilling medium to be used. Factors to be considered should include formation pressures, hole stability, drill cuttings transport, fluid flow regime, lithology,

the presence of corrosive gases and fluids and fluid compatibility with formation water.

Borehole problems can be considerably more severe in a horizontal well than in a vertical well. Therefore, drilling fluids should be tailored to the target formation to insure maximum production.

Wellbore Preparation

Wellbore preparation is a critical process. Two key steps that must be executed properly are (1) sectioning the production casing and (2) spotting the cement kickoff plug.

Sectioning is the process of removing a section of casing at a predetermined depth to allow the proposed radius of curvature to be drilled. The interval to be sectioned depends on the dimensions of the curve and the number of laterals to be drilled. Usually a minimum of 25 feet is cut to accommodate one 30 foot to 60 foot radius curve. For larger radii and/or multiple curves, a larger section is required. It is important that the sectioned interval be located at the exact depth called for in the wellplan. If there is any doubt as to the location and/or the quality of the section, the interval should be underreamed.

Following the sectioning procedure, a cement plug is set at total depth ("TD") or just below the sectioned interval. Cement is brought up through the section and to a depth where at least 200 feet of cement is inside casing. In certain cases, a cast iron bridge plug ("CIBP") must be set just below the sectioned interval and immediately above the top perforation. The CIBP will help isolate the cement plug from possible hydrocarbon contamination. The cement plug is multi-purpose providing zone isolation for the original completion, mechanical strength for the curve drilling assembly to kickoff and toughness to remain intact throughout the rotary drilling process. A period of 48-72 hours should be allowed for the plug to cure. The plug is then dressed off to a depth 8 to 15 feet above the projected kickoff point.

Horizontal Drilling Operations

Following dress off of the cement plug, a pilot hole of approximately 8 to 15 feet is drilled to the kickoff point using a packed hole assembly and the anti-whirl PDC bit. The hole is then circulated clean and the pilot assembly tripped out.

Drilling the Curve

Following the scribe procedure and muleshoe alignment at surface, the CDA is tripped in the hole to approximately 4 feet from the kickoff point. A function test of the tools is performed by checking pump pressure signals at surface. Next, the toolface is oriented with a gyro and the pipe scribed to the protractor plate. Curve drilling commences and realignment of the toolface is made after each foot drilled in the following manner:

1. Drillstring rotation is stopped.
2. The assembly is picked up off bottom.
3. The drillstring is rotated to the left until a pressure port on the deflection sleeve opens; a pressure drop at surface will indicate that the deflection sleeve is locked and moving with the assembly.

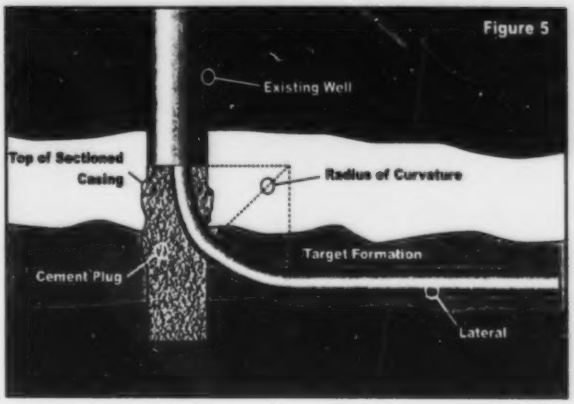
4. The drillstring is rotated farther to the left until the surface scribe line is pointed in the target direction referenced on the protractor plate.
5. The drillstring is then reciprocated to remove drillstring twist and bring the deflection sleeve in line with the surface scribe line.

The frequency of the realignment maneuvers may be decreased to every 2-3 feet drilled if pressure signals appear constant. After drilling approximately 30 feet, a survey is run to check build rates and direction. Based on survey data, drilling may continue or the toolface may be repositioned to correct for any slippage. A second and possibly third survey will be run to fine tune the inclination at the terminus of the curve. When the curve is complete, the CDA is tripped out. The total curve drilling process usually takes 8-24 hours to complete depending on depth, rate of penetration and radius drilled.

Drilling the Lateral

The "Straight Shooter" is run the majority of the time to drill the lateral. The bottomhole assembly ("BHA") consists of the Straight Shooter and the required footage of flexible drill pipe. Prior to drilling the lateral, the curve must be gradually reamed. Once on bottom, drilling resumes with emphasis placed on torque, RPM's and weight on bit. Surveys are usually taken every 100 feet or as needed. When TD is achieved, the hole is circulated clean and the pipe tripped.

Figure 5 is a schematic depicting a lateral drilled from an existing wellbore



using the Rotary Steerable System.

Completing the Lateral

The high curvature of a short radius well limits the rigid tool length that will pass through the curve and into the lateral. Most off-the-shelf completion equipment such as logging tools, perforating guns and packers are too long for short radius application and therefore must be shortened or segmented.

Completion technologies have improved in recent years allowing operators a wider choice of options. While most laterals are left open hole, the curve is usually protected by running a slotted liner of 2-3/8" or 2-7/8" 8rd EUE tubing. Slotted liners can be run to the end of the lateral for acid treatment. Another option is to run coiled tubing in the open hole to apply a jetted or high-pressure treatment throughout the lateral. Recently, two short radius wells (42 foot ROC) were completed running a solid liner with frac subs incorporated into the liner string for fracture stimulation.

A minimum radius of 45 feet for a 4.5" hole is recommended when the completion requires running screens or gravel packs in unconsolidated formations.

Minimizing formation damage by controlling solids and using compatible drilling fluids can significantly reduce completion costs.

Rotary Steerable Advantage

Drilling short radius wells with the Rotary Steerable System offers several distinct advantages:

- Lower in cost to manufacture, repair and operate than conventional mud motor systems.
- Works inside 4.5" casing.
- Drills a 30 foot radius of curvature.
- Lost-in-hole liability is greatly reduced.
- Drills a smoother planar wellbore.
- Continuous rotation enhances hole cleaning.
- Improved penetration rates.
- Less costly surface components.
- Compatible with any drilling medium.
- Well suited for drilling laterals of 200 feet – 1000 feet.

Case Histories

Figures 6 through 11 offer a sampling of the wells drilled with the Rotary Steerable System and indicate the capability and versatility of the system.

Figure 6 shows a well drilled for Texaco in Hutchinson County, Texas. Two 4.5" laterals were drilled with mud to complete a newly drilled vertical hole. Completion entailed sweeping the lateral with coiled tubing to spot acid. Total job time was approximately 3 weeks for the horizontal operation including well preparation and completion. Total well cost was approximately $500,000.

Figure 7 depicts a well drilled for Oxy USA in Seward County, Kansas. One 4.5" lateral was drilled with foam as an extension for a new vertical hole. Completion included a coiled tubing/acid treatment. Total job time for the horizontal operation was 7 days of daylights only. Total well cost was $219,000.

Figure 8 shows a well drilled for Trueblood Resources in Beaver County, Oklahoma. One 3.875" lateral was drilled inside 4.5" casing as a new well completion. The lateral was drilled with an oil-based mud. No completion or cost data is available. Total job time for the horizontal operation was 6 days.

Figure 9 illustrates a well drilled for Oklahoma Natural Gas in Creek County, Oklahoma. This was a re-entry inside 7" casing and two laterals were drilled in opposing directions. Radius of curvature was 27 feet and 28 feet respectively. The laterals were drilled with a water based balanced mud system. Total job time for the horizontal work was 3-1/2 days and the total project cost was approximately $175,000.

Figure 10 shows a well drilled for Chevron USA in Kern County, California. This was a re-entry inside 7" casing. Up hole perforations were preserved by sectioning below the perforations and drilling with a calcium carbonate system that temporarily sealed

the perforations. Completion included running two frac subs in a solid liner string and applying a 200,000 lb. sand fracture stimulation. Four days were required to drill the horizontal segment.

Figure 11 depicts a well drilled for Phillips Petroleum in Ector County, Texas. This was a re-entry inside 5.5" casing. The horizontal segment was drilled with a weighted water based mud system due to working in a carbon dioxide flood. Completion entailed jetting acid through coiled tubing. Total job time including wellbore preparation, drilling and completion was 3 weeks.

Conclusion

The Rotary Steerable System offers a viable low-cost alternative to operators. The system is especially well suited for use as a re-entry tool in mature highly developed fields or as a completion technology for new wells.

Acknowledgements

Thanks goes to the Amoco team of Tommy Warren, Ken Mason and Tony Mount for their contribution to the development of this technology. A special thanks goes to the men on the brake handle -- Joe Chavez, Lawrence Felder, Terry Stanton and Randall Hicks -- whose dedication in the field has made Torch Drilling Services L.L.C. the recognized leader in running the Rotary Steerable System.

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4. Warren, T.M., "Slimhole Rotary Steerable System Broadens Applications," World Oil, September 1997, pp. 83-97.

Figure 6

TEXACO E & P
Hutchinson County, TX

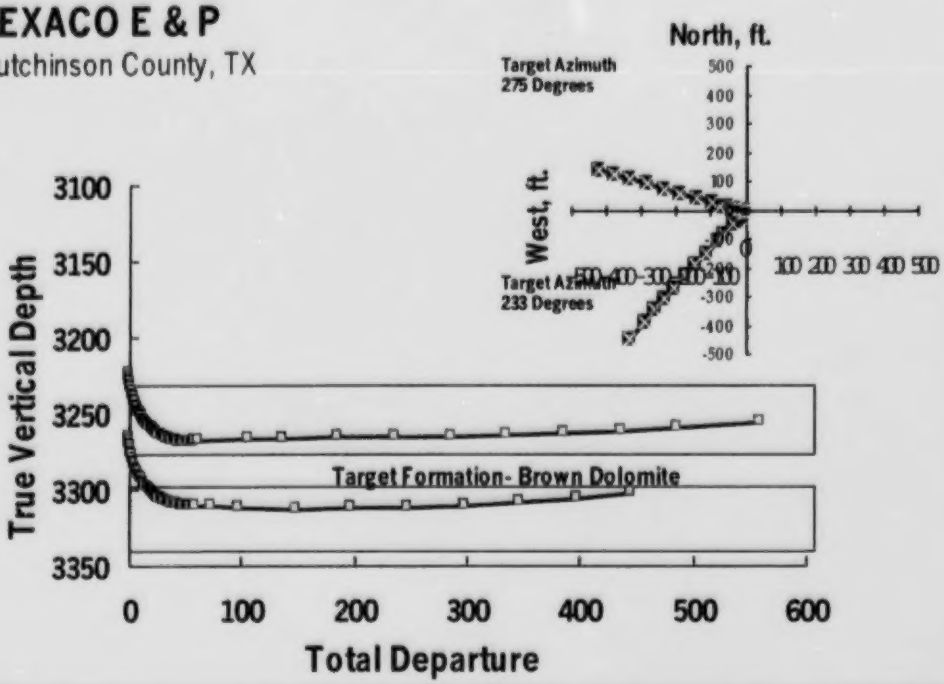
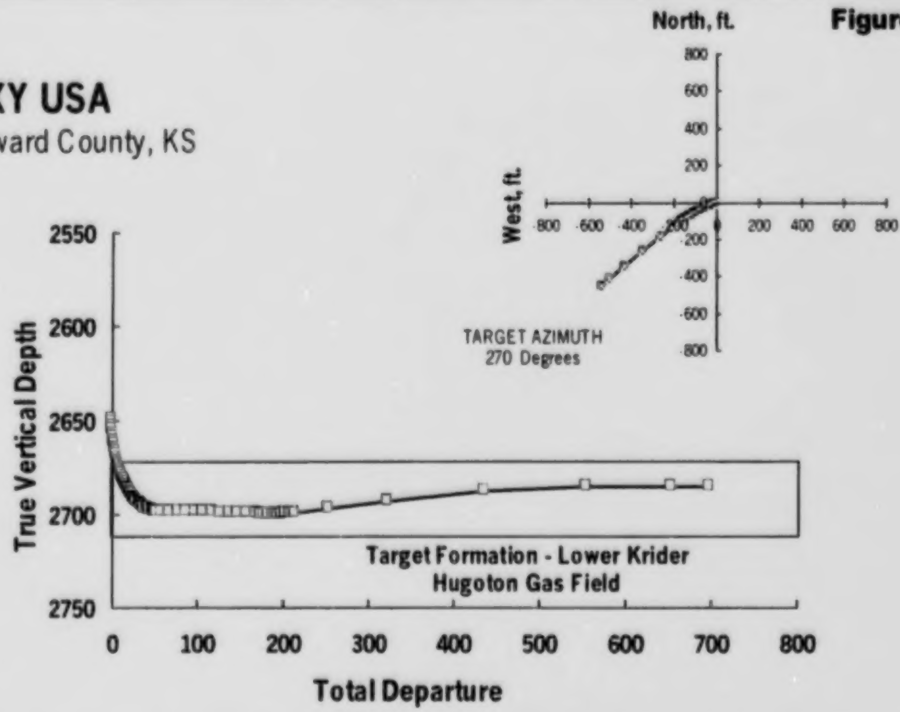


Figure 7

OXY USA
Seward County, KS



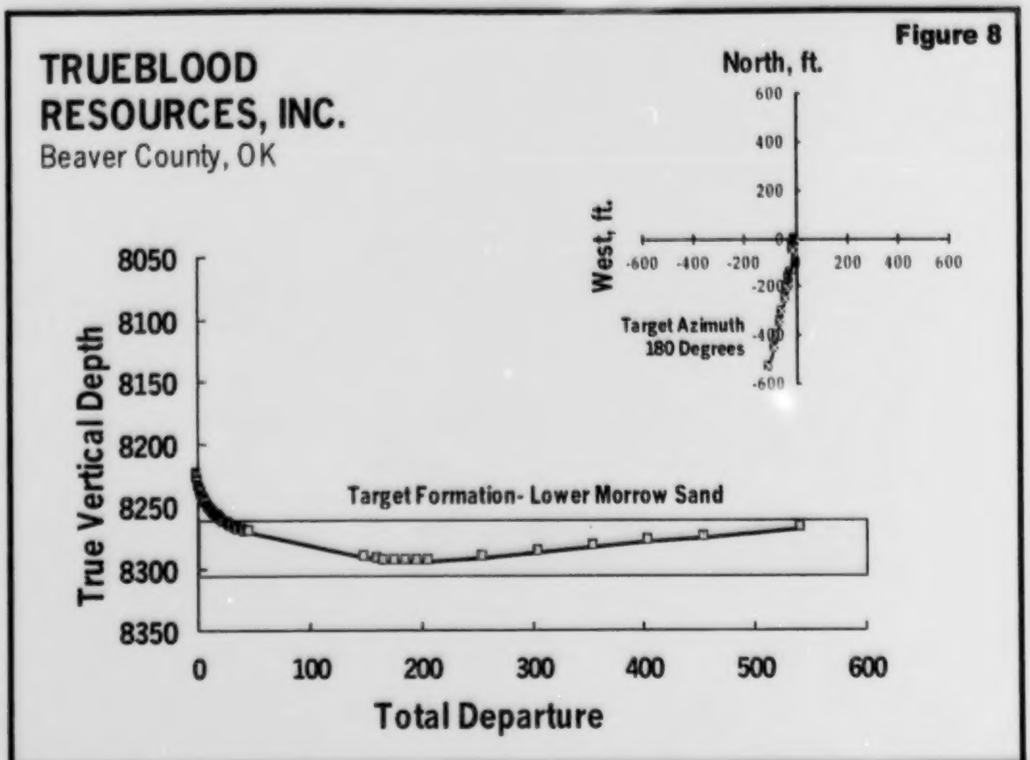


Figure 8
TRUEBLOOD
RESOURCES, INC.
Beaver County, OK
North, ft.
West, ft.
Target Azimuth
180 Degrees
True Vertical Depth
Target Formation- Lower Morrow Sand
Total Departure

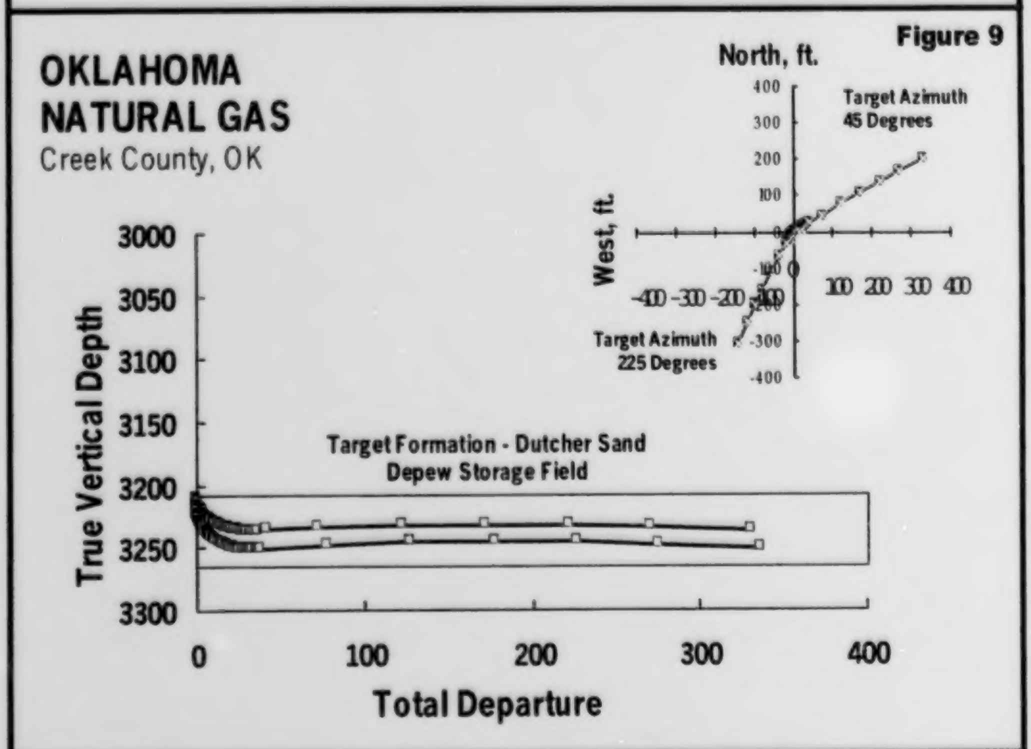


Figure 9
OKLAHOMA
NATURAL GAS
Creek County, OK
North, ft.
West, ft.
Target Azimuth
45 Degrees
Target Azimuth
225 Degrees
True Vertical Depth
Target Formation - Dutcher Sand
Depew Storage Field
Total Departure

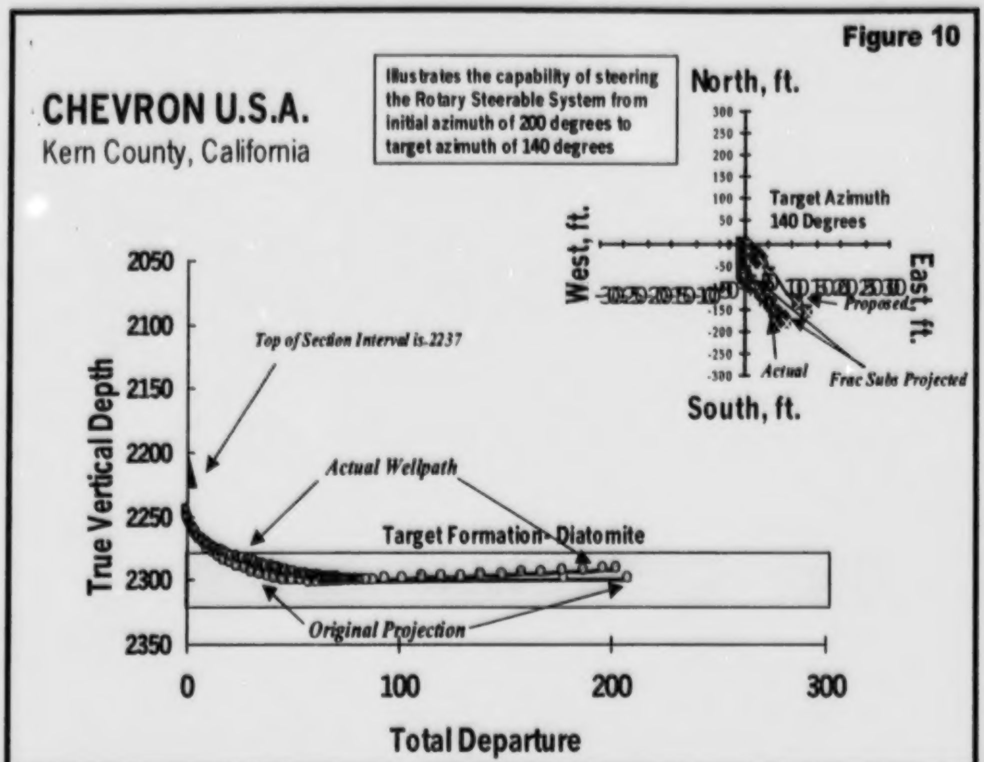


Figure 10
CHEVRON U.S.A.
Kern County, California
Illustrates the capability of steering the Rotary Steerable System from initial azimuth of 200 degrees to target azimuth of 140 degrees
North, ft.
South, ft.
West, ft.
East, ft.
Target Azimuth 140 Degrees
Proposed
Actual
Frac Subs Projected
Top of Section Interval is 2237
Actual Wellpath
Target Formation- Diatomite
Original Projection
True Vertical Depth
Total Departure

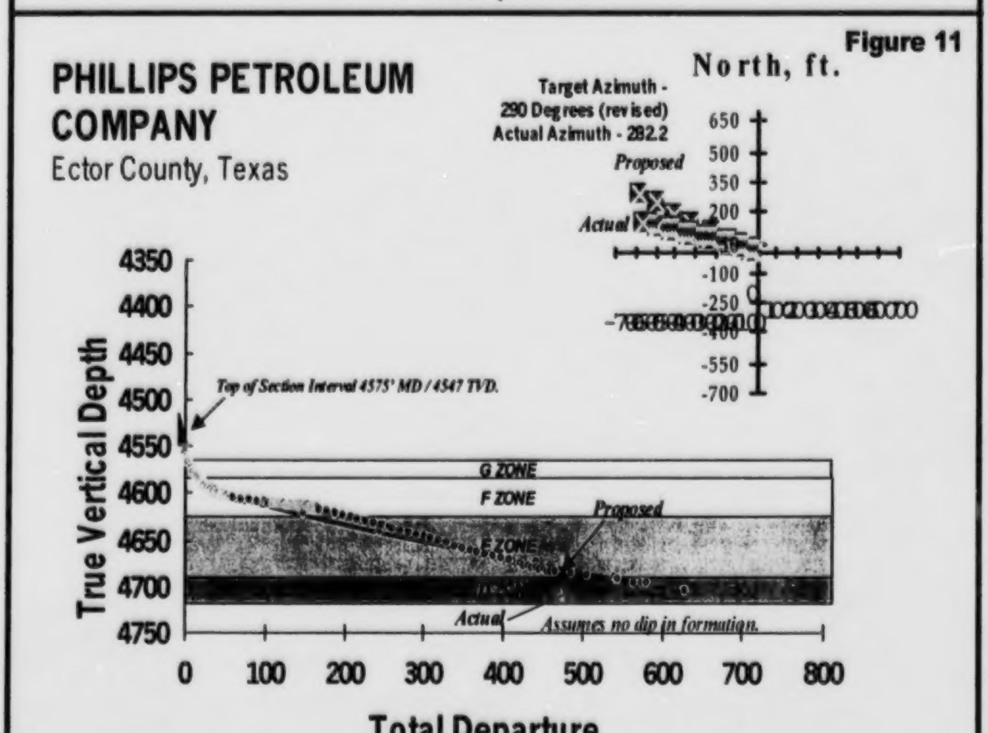


Figure 11
PHILLIPS PETROLEUM COMPANY
Ector County, Texas
North, ft.
Target Azimuth - 290 Degrees (revised)
Actual Azimuth - 282.2
Proposed
Actual
Top of Section Interval 4575' MD / 4547 TVD.
G ZONE
F ZONE
E ZONE
Proposed
Actual
Assumes no dip in formation.
True Vertical Depth
Total Departure

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J

Microbial Technology Improved Oil Production & Gas Control

John Barnett
BioConcepts, Inc.

Microbial Technology for Improved Oil Production & Gas Control

By John Barnett
BioConcepts, Inc.

Microbial enhanced oil recovery is a biological treatment that is fast becoming an accepted method of maximizing production. BC10 Bacteria™ treatments can remove paraffin-based skin damage from formation faces, thus improving permeability and increasing well production.

Increased Oil Production

Favorable changes in flow characteristics such as reduced viscosity and increased volatiles are another aspect of bacterial treatment that can yield more oil. BC10 Bacteria™ treatments for control of scale and corrosion employ several substances of microbial metabolism that have chelating, anti-precipitation, filming or bio-surfactant activities. Our bacteria offer the same properties, but not the liabilities, of conventional chemical products used as scale and corrosion inhibitors. By using the appropriate microbial treatment, water flood operations can achieve increased effectivity at reduced pressures. Microbes also offer vast potential for improved sweep efficiency as they mobilize residual oil while traveling through the reservoir.

Oil and gas production can be significantly hindered by various types of well bore and near-well bore formation damage. This formation damage can either plug up perforations or reduce the effective permeability of the oil-bearing formation. Existing well stimulation methods used to remedy these problems can often have high chemical, pumping and disposal costs, and can produce additional damage if not conducted properly. The most commonly applied method to treat production problems caused by these organic deposits is "hot-oiling". However, this method often poses a more serious problem of reintroducing undesirable organic deposits back into the formation and has limited effectiveness in preventing or inhibiting buildup of additional deposits.

Crude oil that contains paraffin mixtures (waxy hydrocarbon mixtures) will thicken and solidify the crude at a certain temperature called the "cloud" point. Oil field operators usually halt pumping intermittently to clean out paraffin-clogged lines with a device that flushes heated oil downhole to melt the paraffin. If the well is not regularly treated with hot oil, sucker rods may stick and/or break. Also, it may damage or fill the porosity that the hot oiling is trying to open. Both halting pumping and hot oiling are expensive and result in decreased oil production.

BC10 Bacteria™ treatments remove particulates and organic and inorganic precipitates from wellbores and the surrounding formation, thereby restoring permeability and improving the economics of producing and increasing production of older wells that might otherwise be abandoned. BC10 Bacteria™ is a proprietary non-pathogenic bacteria formulation. It is a specialized combination of bacteria derived from the families of bacteria known to degrade petroleum constituents. BC10 Bacteria™ treatments increase oil production approximately 35% to 100%.

Freeze Resistant

Tests in the Northern United States have shown that wells treated with BC10 Bacteria™ exhibit fewer freezing problems than wells not treated with this program. In extreme freezing temperatures, as low as 50° below zero, treated wells have continued to flow maintaining the oil viscosity. The well water does not freeze due to the bacteria by-products that secrete aldehydes and alcohols similar to those used in anti-freeze.

MEOR Compliant

Another advantage of the BC10 Bacteria™ treatment is that it is considered a form of the MEOR (Microbial Enhanced Oil Recovery) program that may have certain tax advantages in some states. Of course, this will vary from state to state however, it can be a source of profit that should be investigated.

Storage Tanks

Stable emulsions, sediments, and precipitates in storage tanks are a frequent problem in oil production. BC10 Bacteria™ products have been very successful in improving oil and water breakout and in solubilizing precipitates.

Controls Salts

The BC10 Bacteria™ produces surfactants which cause paraffin and other precipitates to go back into solution. They also reduce available oxygen which inhibit reactions such as:

$FeSO_3 + O = FeSO_4$ (Sulfite to Sulfate)

Iron sulfate is less soluble than iron sulfite. The bacteria will use calcium and sodium ions in metabolic reactions to control salts from building up on surfaces and staying in solution. Metabolically produced polysaccharide films that will coat surfaces and prevent the nucleation of scale molecules.

Corrosion Barrier

The BC10 Bacteria™, a facultative bacteria, will scavenge the available oxygen thus making it less available for oxidation reactions such as corrosion. In addition, the polysaccharide produced through metabolism will coat internal parts placing a barrier between metal and corrosive elements.

Reduces Emulsions

Due to surfactant production and the elimination of free oxygen, emulsions tend to break down or not form at all. In addition, BC10 Bacteria™ treatments reduce the problems associated with emulsions in older wells. This problem occurs when the wells become older and the water and oil is more difficult to separate. The bacteria treatments prevent emulsion from occurring in the well resulting in the production of more oil than water.

Cost Effective

BC10 Bacteria™ is considered a natural, safe, non-toxic and inexpensive alternative to the removal of oil pipe deposition. BC10 Bacteria™ applications are a fraction of the costs of acids, solvents, hot oil treatments and mechanical pigging historically utilized for restoration of oil production. BC10 Bacteria™ represents a major technological breakthrough for the oil producer allowing for easy application without the need to use complex and expensive equipment.

Well Evaluation

Pre-treatment assessment is essential to evaluate microbial applications. BCI Environmental, Inc. offers the most extensive laboratory technical support and research assistance available to the petroleum industry for biological applications. Capabilities include gas or liquid chromatography, viscosity, surface and interfacial tension, cloud and pour point, and water analysis. Our lab can also offer simulated core flooding and other testing that requires anaerobic conditions. Our petroleum engineers and field technicians are available to provide guidance anywhere in the world for design of treatment programs and training on product application. Evaluating a well for treatment involves a review of historical data; reservoir conditions including bottom-hole temperature and pressure, physical properties of the produced fluids such as paraffin content, chlorides, and H_2S; and mechanical design characteristics, both surface and downhole. BC10 Bacteria™ products are used in all types of formations and in both natural and artificial drives. An added benefit to the BC10 Bacteria™ line is ease of product handling. No special procedures are required and there are no compliance problems. Due to the technical nature of the product and the application being treated, our technicians will need to work with you before, during and after our BC10 Bacteria™ is applied.

Quality Assurance

Most bacteria products and cultures are sold in liquid form which make them difficult to store and transport. These products are often manufactured in mass quantity and the assurance of quality live bacteria is not obtainable without available food substance during storage. Lack of a food substance causes the bacteria to turn canabilistic and eat each other before being used in the desired application.

Each species used in BC10 Bacteria™ is developed independently, freeze dried then blended in the proper ratio of cultures to ensure the desired results. The bacteria blend is freeze dried onto bran to reduce transportation cost due to weight and to insure the quality of bacteria. This unique process enables our staff to create new bacteria blends for specific applications. All our cultures are developed independently and monitored in a secure, safe environment to control the quality and effectiveness of our products.

Oil Well & BC10 Bacteria™ Characterization

Deposit Characteristics

- Paraffin, Asphaltenes, Resins, Gums, Salt Crystals, Scales, Clay, Slits, Sand, Water
- Paraffins - straight or branched non-polar Alkanes, 20 - 60 carbon atoms, Melting range 90° - 210°F
- Asphaltenes - high molecular weight cyclic aromatic compounds containing nitrogen, oxygen and/or sulfur in structure, negative-charged polar compounds
- Temperature and pressure changes greatest factors in depositing process
- Paraffin - micro and macro crystals
- Asphaltenes- Colloidal suspensions
- Remaining gas deposits can be utilized or changed

Bacteria Characteristics

- Large protein molecules
- Water and miscible oil control
- Surface tension breakers
- Strong attraction to organic molecules
- Disrupter to colloidal and macrocrystalization aggregation process
- Chelating characteristics for minerals and related nutrients
- Ability to penetrate & breakup biofilms (polysaccharide-type surfaces)
- Biocatalytic action (enhanced biological reactions)

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- Non-toxic & harmless in the environment
- Production of natural gas & control of H_2S

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K

In-Situ Acid Production for Completion and Stimulation of Horizontal Wells

Ian D. McKay and Ralph E. Harris
Cleansorb Ltd., U.K.

In-Situ Acid Production for Completion and Stimulation of Horizontal Wells

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At various stages during the life of a well, production may be limited by the presence of materials which reduce or impede the flow of hydrocarbons and reduce the value of the well. Examples of materials which limit production are filter cakes deposited on the inside of the wellbore during drilling, residual filter cake from incomplete clean-up, or production related damage such as near-wellbore scales. In order for the well to produce at its maximum potential, the effective removal of the damaging material is needed. If this is achieved, increases of up to several fold in production may result.

In undamaged wells, potential exists for achieving higher production rates through increasing the permeability of the formation or the conductivity of fractures which intersect the wellbore. Productivity gains are not as high as can be achieved from damage removal, but may still be of the order of several tens of percent.

Hydraulic fracturing of wells can give several fold stimulations of production if the damage arising from the gels typically used in the process is effectively removed.

Gravel packing of wells offers an effective solution to sand control but efficient gravel packing requires the presence of an intact filter cake while packing the well. This must then be efficiently removed after the treatment to obtain high production rates.

Acidizing

Several forms of well damage, including filter cakes, scaling and damage from acid-sensitive gels such as guar-borate cross linked gels are amenable to treatment with acid. Acid treatment of wells has been used for over 100 years, in many cases with significant success. On vertical wellbores with short production intervals, treatment with conventional acids is generally highly effective.

However, conventional acid has a number of limitations. The high reaction rate of the acid means that zonal coverage may be poor. The acid will quickly find a weak point in a filter cake and spend rapidly on the formation preventing much of the acid reaching its intended destination and leaving much of the filter cake in place. To compensate for this, high dose rates of acid and high pump rates are often employed in an attempt to improve the zonal coverage. There is also generally a need to use corrosion inhibitors which increase the cost and which are often toxic.

The move within the industry to the widespread use of horizontal or deviated wells has made it more difficult to place acid effectively over the much longer production intervals which are now commonplace.

Ideally, acid systems should be available which would permit the uniform removal of filter cake from the whole of a wellbore, even if the wellbore is very long, radial delivery of acid

deep into the formation to achieve "true" matrix acidizing, or delivery deep into fractures to increase the conductivity of the fractures.

Over the last thirty to forty years a number of approaches have been suggested by which the reaction rate of conventional acids can be reduced and the zonal coverage improved. These include:

(a) Emulsifying the aqueous acid solutions in oil (or solvents such as kerosene or diesel fuel) to produce an emulsion which is slower reacting.
(b) Dissolving the acids in a non-aqueous solvent.
(c)The use of non aqueous solutions of organic chemicals which release acids only on contact with water.
(d) Gelling of the acid.
(e) Use of chemically retarded acids (using an oil wetting surfactant).

There are advantages and disadvantages to all of these methods.

In addition to the above, placement of acid through coiled tubing can go some way to giving better delivery of acid, but problems with a high reaction rate remain. Also, in very long horizontal wells it may not be possible to place coiled tubing to the end of the wellbore due to friction and spiralling of the tubing.

There remains a need for an acidizing method which allows the efficient delivery of acid to the whole of a target region. Applications for such a method include the removal of filter cake from horizontal wells, stimulation of horizontal wells, deep matrix acidizing, deep stimulation of natural fracture networks and the removal of filter cakes in gravel packs.

In-situ acid production

Our approach to achieving efficient acid delivery has been to develop a process which generates acid *in-situ*. The treatment fluid, which is initially non-acidic, is placed downhole in the wellbore or formation. The fluid then produces acid over a period of a few days (typically 2 days).

The Arcasolve acidizing process is based on the use of enzymes to hydrolyse suitable molecules, which are themselves neutral, but which generate acids when hydrolysed.

Enzymes

Enzymes are natural catalysts which are present in all biological systems. They are polymers of amino acids with a high molecular weight (typically 30,000 to 200,000 daltons, although some useful enzymes are larger). Their role is as catalysts which speed up the chemical reactions required for life. In most biological systems enzymes operate under relatively mild conditions of pH and temperature. Many of the reactions they catalyze can only be performed chemically under much more extreme conditions. Their activity is often extremely specific; individual enzymes can only break down or synthesize certain compounds. Hundreds of different catalytic activities are available. Relatively small amounts of enzyme are needed as the enzyme is not consumed in the reaction. As a catalyst it is regenerated in the reaction and the catalytic cycle repeats itself.

The ability of enzymes to catalyze specific reactions has made them highly useful in a number of major industrial applications. Isolated enzymes can be used to either degrade or produce specific chemicals. Industrial enzymes are generally extracted from bacteria or fungi, although animal and plant enzymes are also used.

The world market for industrial enzymes is worth approximately $1500 million per year. Enzymes are already widely used in a number of major industries including the brewing, distilling, wine, animal feed, baking, brewing, dairy, cleaning, detergent, fats and oils, leather, personal care, pulp and paper, food and drink, pharmaceutical, fine chemical, diagnostic and textiles industries.

Enzymes are normally highly soluble in water, are biodegradable and pose no significant environmental problems. They are often used in industrial processes which replace more hazardous conventional chemical methods.

Industrial enzymes are increasingly being used in high efficiency processes which can convert high concentrations of substrate to product in hours. For example, at least 30% of acrylamide produced worldwide is now made from acrylonitrile by an enzyme based process. The process produces a 65% w/v concentration of product. Another high volume industrial process which uses enzymes is the hydrolysis of starch to produce sugars.

Enzymes have previously been used in the oil industry in relatively small volumes, primarily as polymer breakers. In the polymer breaking application, the enzymes are used to remove something which is no longer desirable, i.e. polymer in filter cakes or fracturing fluids.

Cleansorb is now using enzymes to generate useful chemicals *in-situ*. Our first commercial process uses enzymes to produce acid, *in-situ*. This then reacts with acid soluble or sensitive material to achieve a desired effect e.g. removal of filter cake, increase in permeability of the rock matrix or breaking of acid sensitive gels.

Practical aspects of *in-situ* acidizing

Operationally, the process is relatively straightforward. There are two components. The first component, Acidgen, which is the acid precursor blend, is supplied in drums or IBCs (Totes) and is completely dissolved in water by circulating the water to provide agitation and introducing the Acidgen into the stream of water. For onshore jobs, mixing is conveniently carried out in frac tanks and for offshore use well cleaned mud pits with paddle blenders (on drilling rigs) or other suitable size tanks can be used. The enzyme catalyst, supplied in Jerry cans or drums, is then added. When the whole fluid has been thoroughly mixed the formulated Arcasolve fluid is pumped downhole and left for the required period.

Arcasolve fluid constituents and reaction products are low hazard, non-toxic and readily biodegradable. Spent Arcasolve fluid contains calcium acetate and alcohols and present minimal disposal problems or threat to the environment.

The individual components of the Arcasolve fluid are stable for at least a year at ambient temperature (Acidgen acid precursor) and six months at 25° C (enzyme) respectively.

Applications of the Arcasolve *in-situ* acidizing process

A. Mud damage removal. To use the process to remove filter cakes in new horizontal wellbores, the drillstring may be kept in place and the drilling mud displaced to a clean fluid, leaving the filter cake still in place. The mixed Arcasolve fluid is then pumped through the drillstring and fills the wellbore from the toe of the well. The presence of an intact filter cake actually aids in the placement of the fluid. The drillstring is then withdrawn. Optionally, the drillstring may be withdrawn at the same time the fluid is pumped. The well is then shut-in and acid is produced over a couple of days, leading to removal of the filter cake.

Laboratory data indicates very effective clean up of the filter cake from water based muds in carbonate core tests. Regain permeabilities higher than 100% have been obtained in some core tests. Where oil based muds are used, addition of a non-ionic surfactant is required to assist the reaction of the produced acid with carbonate, leading to filter cake removal.

Treatment of new horizontal wells has moved into the field this year with a treatment of a very long offshore horizontal well in the Middle East. Extensive laboratory tests indicated that Arcasolve gave the best clean up of any method tested by the operator. The operator will be evaluating the process over several more treatments this year and next. Treatments will also commence in both onshore France and in the UK Sector of the North Sea during this year.

Arcasolve has also been successful in treating under-performing horizontal wells. A well in offshore West Africa which was known to suffer from residual drilling damage was treated. This well had been treated with bullheaded hydrochloric acid during completion. An initial production rate of 2000 bopd declined to 700 bopd within a month and to 500 bopd within 18 months. Over the next 5 years, production gradually declined to 200 bopd. Following treatment with Arcasolve, bullheaded into the well, production resumed at 800 bopd and has now levelled out at 500 bopd. The treatment costs were paid back in only a week. The operator is proceeding to treat several more wells in the same field.

B. Deep matrix stimulation. Arcasolve has been used for matrix stimulation treatments where the fluid is pumped radially into (nominally) undamaged vertical wells to increase the matrix permeability to at least several feet, leading to increased production rates. This is useful in areas where wells are on waterflood and fracturing of wells to increase production is not an option. Treatments designed to give 20% increase in production gave increases of up to 50% indicating that some of the wells were probably suffering

from near wellbore formation damage that the operators were not aware of. Most of the wells treated in this way were relatively low producers, making only a few tens of barrels per day. Payback took several weeks.

C. Removal of filter cakes in gravel packing. This application is currently being evaluated in the laboratory with a view to field treatments later this year. Excellent removal of filter cakes has been obtained. The Arcasolve fluid may be used as a base fluid for carrying out the gravel packing or introduced after the pack has been placed. The former is probably the preferred option.

D. Fracture stimulation. The process may be used to deliver acid deep into natural fracture networks to improve their conductivity and increase production.

E. Breaking of guar-borate gels. Incorporation of the chemicals into fracturing fluids allows uniform viscosity reduction throughout the fluid after a predetermined period of time.

The amount of acid produced, and the rate of acid produced are determined by the requirements of the application and the Arcasolve is formulated accordingly. The amount of acid the formulation can make is determined by the concentration of Acidgen used and the rate of acid production is determined by the concentration of the enzyme catalyst. Typically, the efficient delivery of about 5% acid will be enough for filter cake removal and matrix stimulation applications. For gel breaking, the production of lower amounts of acid may be sufficient. Where gross dissolution of acid soluble material is needed, higher concentrations of suitable acid precursors can be used.

The basic acidizing process dissolves carbonate and generates an acetic acid-acetate buffer downhole. For applications where combined acidizing and polymer breaking are sought, polymer breaking enzymes may be incorporated into the Arcasolve formulation. The buffer provides ideal conditions for the activity of these enzymes including starch breakers and xanthan breakers, which typically have an optimum pH for activity in the slightly acidic region (pH 3 to 6). The presence of the buffer means that the enzymes are working at maximum efficiency and relatively low concentrations of enzyme breaker may be needed. Other breakers, such as oxidants, may also be incorporated into the formulations to give a two pronged attack on the different components of filter cakes (carbonate LCM, carbonate fines and biopolymers) or on other forms of damage which contain polymers, such as biofilms.

Conclusions. *In-situ* acid production is a novel, simple, effective and very low hazard approach to acidizing. It has a number of advantages over previous acid systems. Field treatments are now proving the utility of the process in a number of acidizing applications, particularly where excellent zonal coverage is required. The process is particularly suited to the removal of near wellbore damage such as filter cake. The process is a useful addition to the "toolbox" of chemical treatments available to operators for maximising the NPV of their assets.

IMPROVING WELL PERFORMANCE

		SKIN
DAMAGED WELL		high
	Remove damage	↓
UNDAMAGED WELL		zero
	Further stimulation	↓
STIMULATED WELL		negative

ACIDIZING

Conventional acids give effective damage removal/stimulation in many circumstances

BUT

- High reaction rate causes problems in placement
- Hazardous in use
- Needs corrosion inhibitors

IMPROVED ACIDIZING

Will benefit:

- Filter cake removal in long horizontals
- "True" deep matrix acidizing
- Delivery into fractures
  etc.

Targets are UNIFORM ACIDIZING and GOOD ZONAL COVERAGE

IMPROVING ACID PLACEMENT

Previous solutions include:

- Emulsification
- Dissolving acids in non-aqueous solvents
- Gelling
- Chemically retarding
- Placement via coiled tubing

IMPROVING ACID PLACEMENT

Our solution:

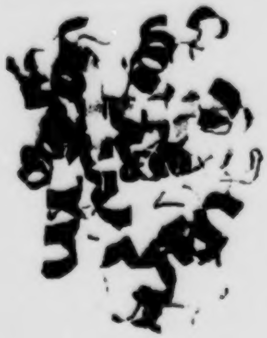
IN-SITU PRODUCTION OF ACID

$$\text{Precursor} \xrightarrow{\text{Enzyme}} \text{Acid}$$

ENZYMES

- Natural catalysts (proteins)
- Over 2000 different enzymes identified - each catalyze specific reactions
- Large molecules - typically 30,000 to 200,000 Daltons
- Industrial enzymes can be isolated from a number of sources
- Many enzymes can operate in harsh aqueous and organic environments

ENZYME MOLECULE



INDUSTRIAL ENZYMES

Markets include:

Brewing, distilling, wine, animal feed, baking, brewing, dairy, cleaning, detergent, fat & oils, leather, personal care, pulp & paper, food & drink, pharmaceutical, fine chemical, diagnostic and textiles industries

Market value > $1,500 million p.a.

ENZYMES IN THE OIL INDUSTRY

Previous use:

- polymer breaking

Our new use:

- *in-situ* generation of useful chemicals

ACID PRODUCTION

Arcasolve (TM) process

APPLICATIONS FOR *IN-SITU* ACIDIZING

- Mud damage (filter cake) removal in new wells incl. gravel packed wells
- Damage removal / stimulation of mature wells
- Deep matrix stimulation
- Fracture stimulation
- Guar-borate gel breaking

PRACTICAL USE OF ARCASOLVE

1. Drums or Totes of Acidgen mixed with water using recirculation through pump or a paddle blender
2. Enzyme catalyst added and mixed
3. Fluid pumped downhole
4. Well shut in for required period (2 days typical) to allow acid production - well put on production

HORIZONTAL WELL STIMULATION

Example: well suffering near wellbore damage

Offshore well, West Africa, 2000 ft

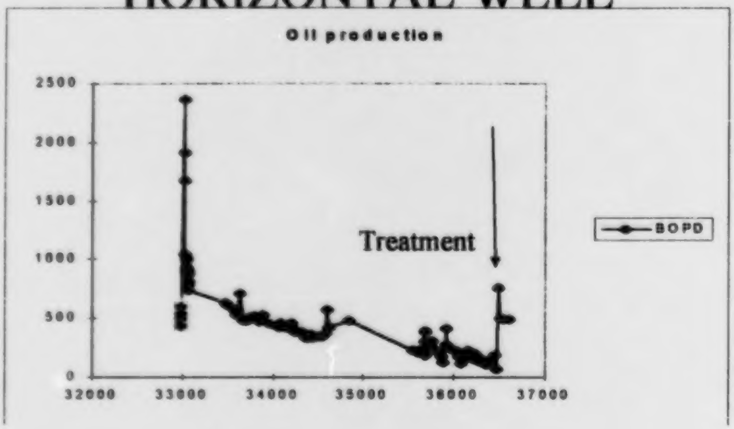
Initial production stabilized @ 500 bopd

Production fell to 200 bopd over 5 years

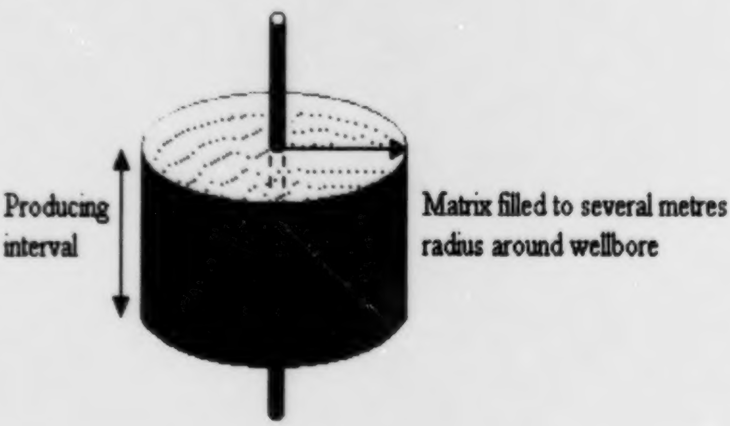
ARCASOLVE bullheaded into well restored production to 500 bopd (sustained for the last 4 months)

(n.b. SPE paper is in preparation which will give details)

STIMULATION OF HORIZONTAL WELL



MATRIX ACIDIZING



MATRIX ACIDIZING

- Treatments designed for 20% increase of undamaged wells
- Up to 50% increase in production rate obtained
- Results indicate damage was in fact present

CONCLUSIONS

- In-situ acidizing using enzymes is simple, novel, effective and low hazard
- Proven in laboratory and in field
- Ensures effective delivery of acid
- Uses include completion and stimulation of horizontal wellbores

L

Options for Improving Communications with Fracture Mechanisms for Horizontal Wellbores in the Charles and Mission Canyon Formations of the Williston Basin

Don Purvis
BJ Services

Options for Improving Communication with Fracture Mechanisms for Horizontal Wellbores in the Charles and Mission Canyon Formations of the Williston Basin.

Don Purvis, BJ Services

Drilling and completing horizontal wells has become an accepted method to connect natural fracture systems and increase the effective drainage radius. In the Madison formation of the Williston Basin, common practice is to complete the horizontal laterals as open hole. Production is through natural fracture swarms combined with tight matrix permeability. When drilling extended reach horizontal wellbores drill cuttings are ground into fine powder by the rotating drillpipe (figure 1). The fines flow into and effectively plug the natural fracture systems. These fines combined with polishing and other horizontal drilling damage mechanisms can significantly reduce or eliminate communication between the wellbore and natural fracture systems. This presentation examines two different methods for minimizing or eliminating this restriction in the flow channel between the naturally fractured formation and horizontal wellbore.

Underbalenced Drilling

The value of underbalanced drilling in these open hole completions has been well established. Underbalanced drilling by design does not build a filter cake in the wellbore. During conventional drilling this filter cake acts as a protective barrier reducing damage to formation permeability from drill cuttings. If the wellbore does not have a filter cake and becomes overbalanced, fine drill cuttings are carried into the formation greatly reducing near wellbore permeability (figure 2). If the well is to be drilled underbalanced, preplanning and on-site engineering are critical in maintaining a continuous underbalanced condition.

Due to the low formation pressures in the Charles and Mission Canyon, an underbalanced condition can not be achieved with low density fluids alone. Gas must therefore be utilized to reduce the effective pressure in the horizontal wellbore. Regardless of the type of gas or injection method utilized, coordination and communication between drilling, gas injection and return fluid handling are critical. This presentation outlines the steps required from initial preplanning through the completion of the horizontal section. Case histories and results are presented. Pre-planning steps are presented along with potential pitfalls and how to avoid them.

Open Hole Stimulation Technique

Once the near wellbore has been damaged via overbalanced drilling or from overbalanced periods while drilling underbalanced, production rates usually fall significantly below the reservoir potential. In order to maximize production rates, some treatment is necessary to remove or stimulate past this damage. This can best be achieved by creating multiple radial fractures or alternately connecting with and widening the natural fracture systems. Several methods have been utilized in the past to achieve this with varying degrees of success.

This presentation examines a different approach to this problem. With this process, it is possible to create multiple radial fractures or connect to natural fracture systems in the most promising sections of the open hole. This is done with jointed tubing placement and the use of an oil soluble diverting medium to block acid from reaching previously treated intervals as well as other sections of the open hole. The use of divertor to channel acid combined with conventional tubing diameters allows achievement of significantly higher bottom hole stimulation pressures. The application of this process is presented along with case histories identifying the challenges and the results achieved to date.

Conclusions

The following conclusions may be drawn based upon this study:

- If the well is exposed to overbalenced conditions during drilling, significant near wellbore damage may occur.
- Underbalanced drilling by nitrogen injection can be an effective method to maximize production in low perm horizontal wells if all precautions are taken to remain underbalanced

- Parasite injection of nitrogen is the preferred method when electromagnetic MWD is not possible
- Nitrogen injection down the drillpipe is the most cost effective when electromagnetic MWD is possible
- Due to lack of a protective filter cake it is critical to remain underbalanced at all times
- Pre job planning and coordination of services is critical
- On-site modeling to optimize nitrogen and fluid injection rates should be done to reduce cost and prevent an overbalanced condition

If near wellbore damage does occur it must be removed through stimulation. Previous methods of stimulating an open hole horizontal wellbore have been expensive and have often had disappointing results.

It is possible to treat multiple discreet intervals in completions of this type without relying on down-hole packers or the cost and restrictions presented by coil tubing units. The placement of a solid diverting material in the annulus presents challenges that need to be addressed by pre-planning the wellbore and rig configuration.

Bottom hole treating pressure analysis and production results from wells treated by the method outlined in this presentation demonstrate success at stimulation of multiple discreet intervals along the open hole lateral. Production rates indicate that the majority of diversion material was dissolved and removed from the wellbore during cleanup. The produced oil during initial production dissolved diverting material in created fractures and wormholes.

A comparison with pre stimulation production and offset wells indicate that substantial increases in production and calculated reserves were achieved by this stimulation process (fig 3-7).

Fig. 1 – Particle Size Distribution (Cuttings From 2300 ft Horizontal)

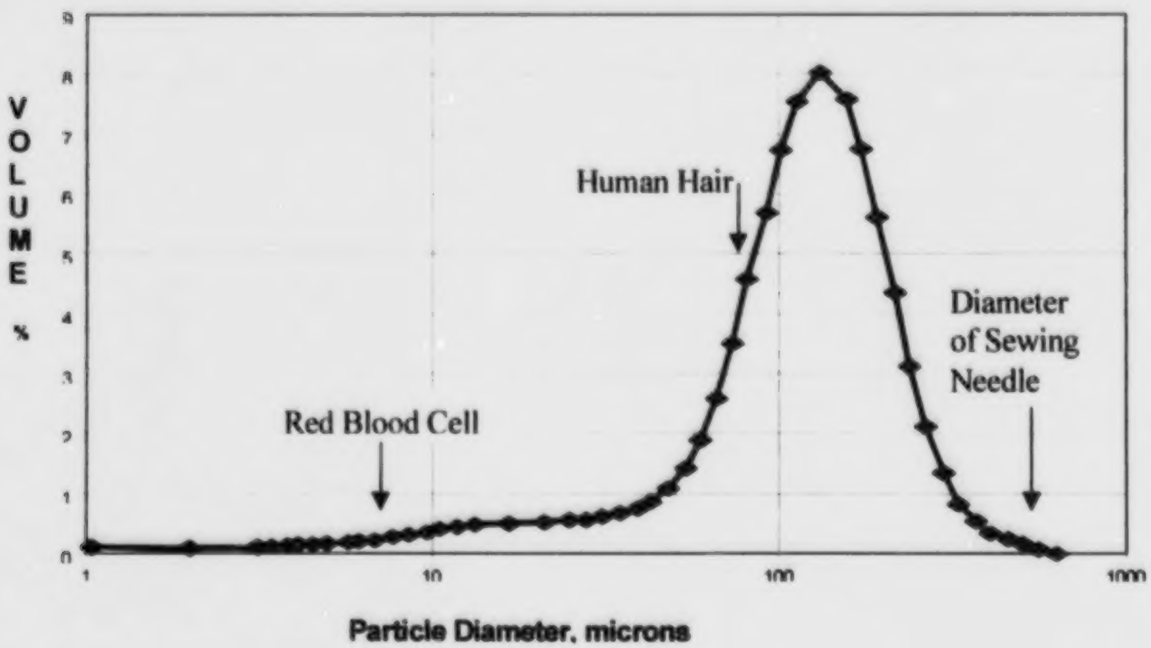


Fig. 2 – Conventional Drilling Damage

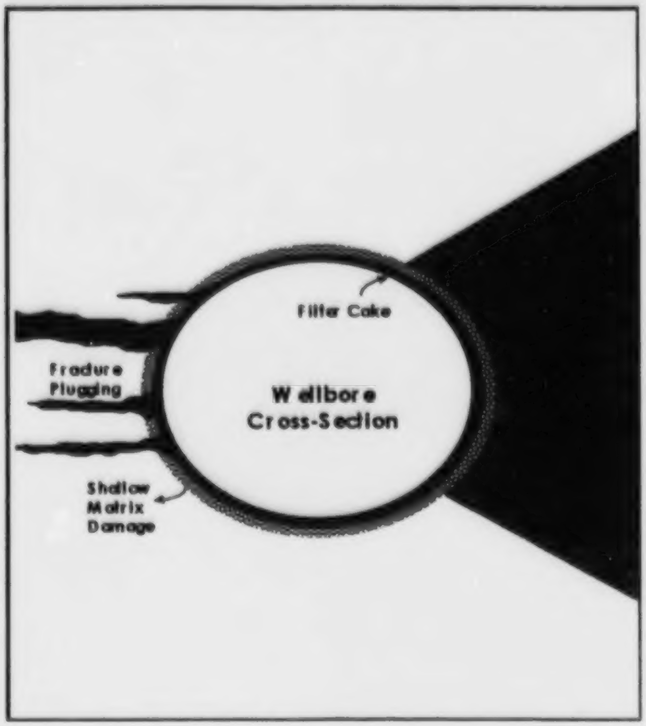


Fig. 3 – Production Results From First Well Treated in Bluell Porosity

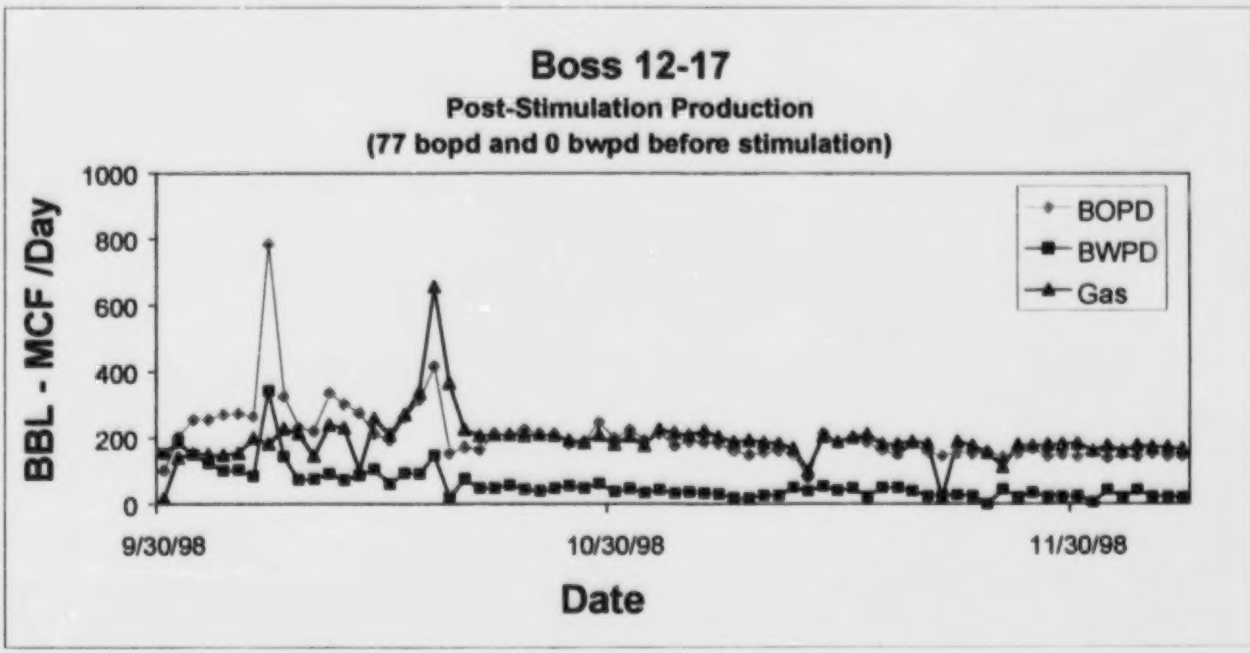


Fig. 4 – Production Results Dual Lateral Bluell Porosity

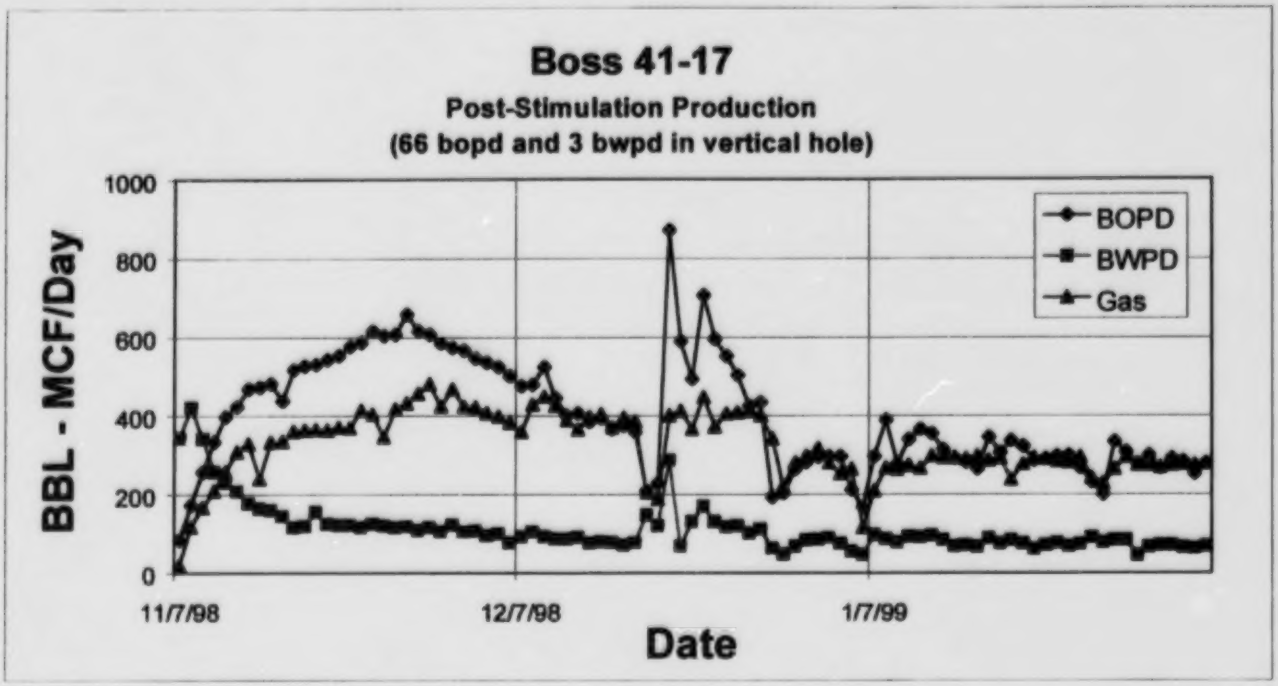


Fig. 5 – Location Of Study Wells Compared to Offsets

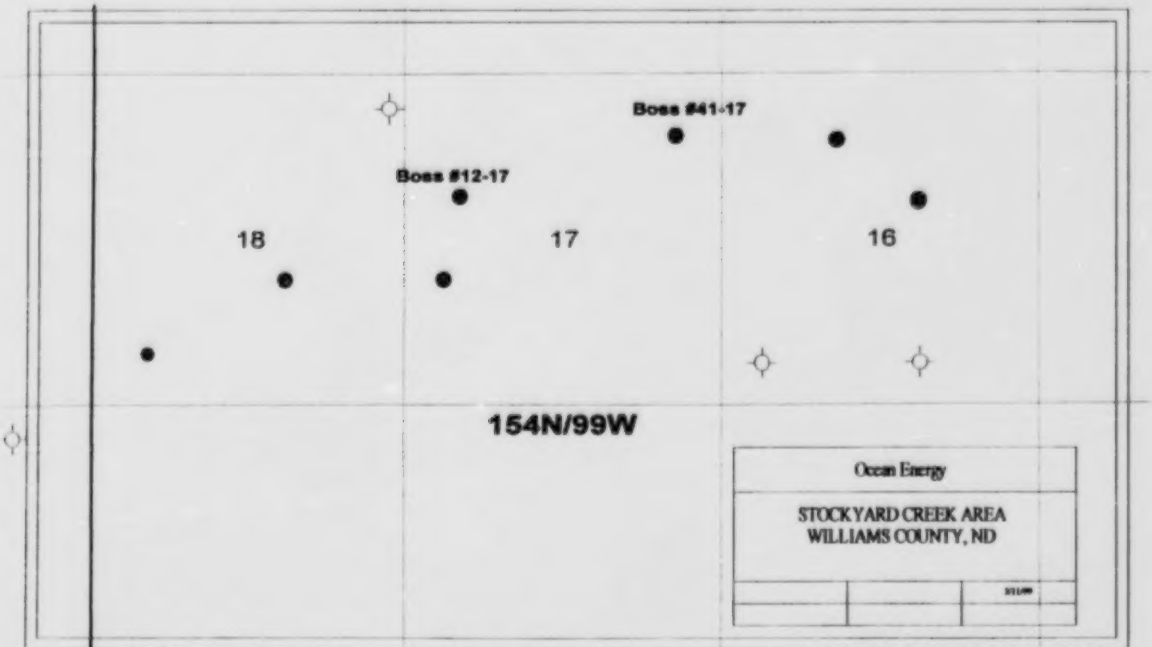


Fig. 6 – Initial Oil Production per 100 Feet of Lateral vs. Offsets

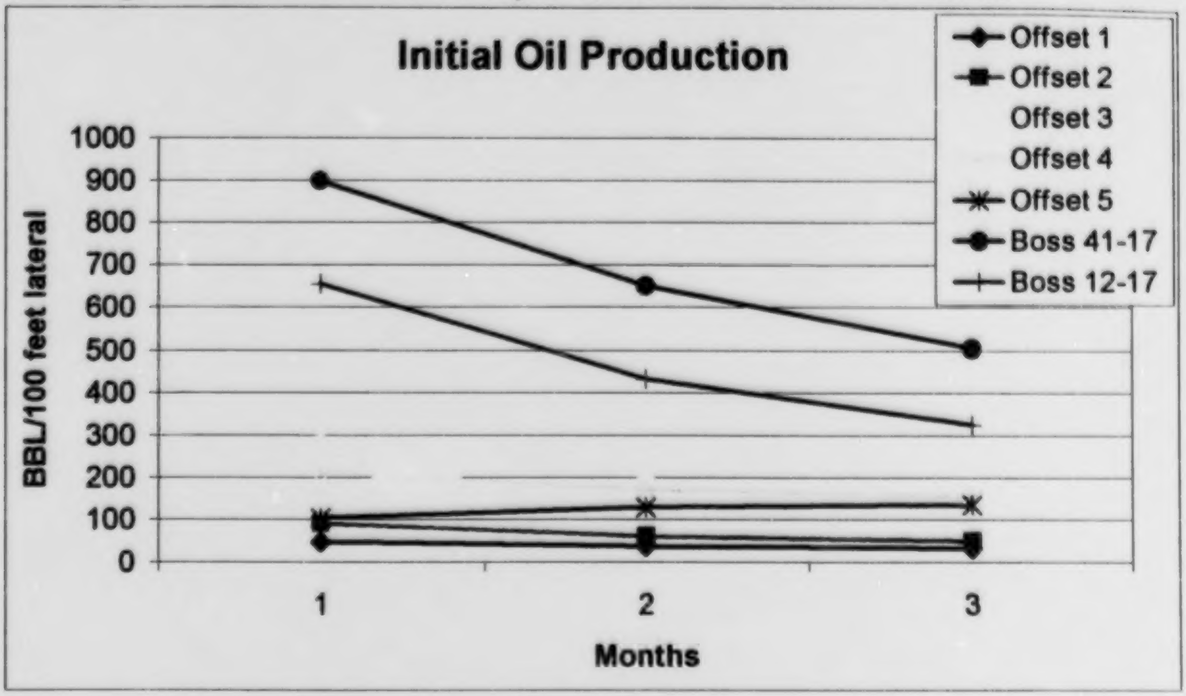
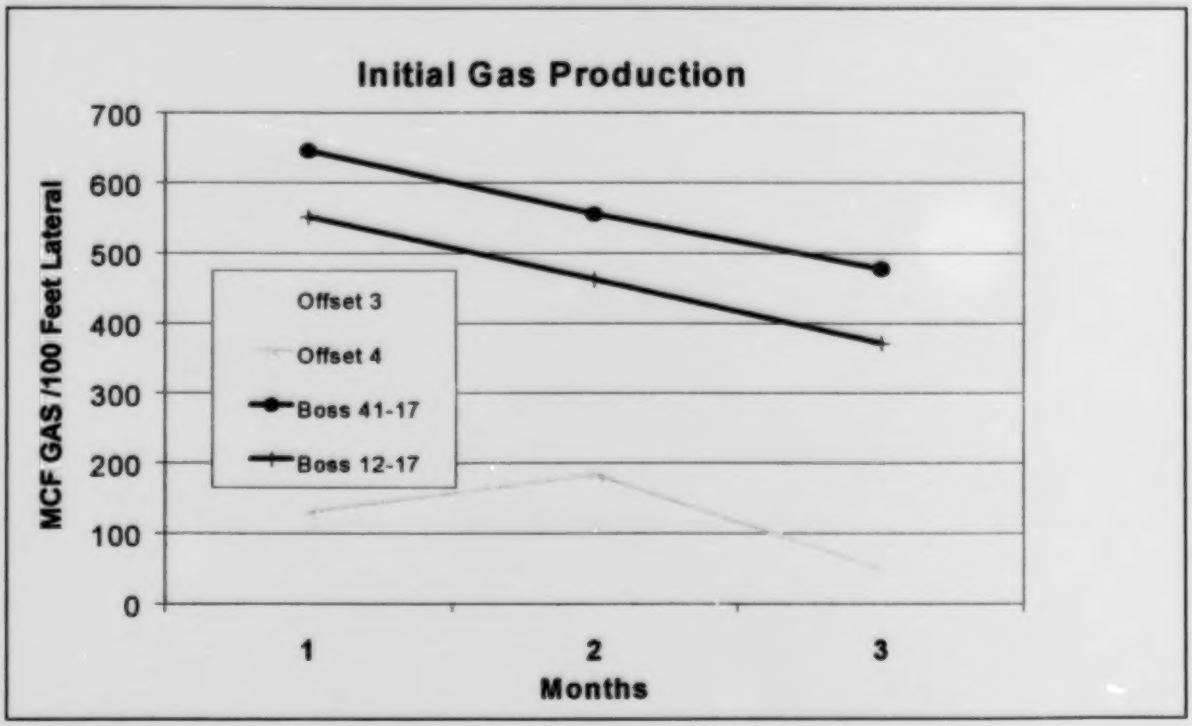


Fig. 7 – Initial Gas Production per 100 Feet of Lateral vs. Offsets



M

Design and Execution of Horizontal CO_2 Injectors in the Weyburn Unit Field

Chris Flannery
PanCanadian Petroleum Ltd.

N

Wayne Field Revisited - Horizontal Update

Jeffrey B. Jennings
GeoResources, Inc.

Wayne Field Revisited – Horizontal Update
By Jeffrey B. Jennings
GeoResources, Inc.

Slide 1

Location Map – Wayne Field is located approximately 45 miles north of Minot, North Dakota in Bottineau County. The field currently produces from 34 vertical wells and 13 Horizontal wells.

Slide 2

Detail Map of Wayne Field - The outlined tracts identify leases with horizontal wells operated by GeoResources, Inc. The southern tract in Sections 31 and 32 is the Oscar Fossum lease with four horizontal wells. The northern tract in Sections 25 and 30 is the Ballantyne-State/Steinhaus lease with one horizontal well.

Slide 3

Structure Map – The structure on the Wayne Porosity trends northwest – southeast and varies in thickness from 10' to 20'.

Slide 4

Reservoir Parameters – Reservoir parameters for Wayne Field.

Slide 5

Drilling Sequence – Drilling sequence for the horizontal wells.

Slide 6

Water Coning Model – A water coning model is used to explain the high water cuts found in the vertical wells. A strong water drive from the bottom and sides of the reservoir combined with a high permeability results in severe water coning. The placement of a horizontal well bore at the top of the section helps to reduce point draw down pressures and provides for better oil recovery.

Slide 7

Wayne Field plot of the average production per well – At the end of 1995, just prior to horizontal development, the average field well produced approximately 280 Bbls per month. With horizontal development this average was significantly improved with production peaking in early 1997 at 1100 Bbls per well per month. The current average production is approximately 550 Bbls per well per month.

Slide 8

Fossum Lease Production – This slide compares Fossum lease production for the vertical and vertical + horizontal wells. The seven vertical wells currently produce approximately 1400 Bbls per month. The four horizontal wells increase current production by another 5600 Bbls to 7000 Bbls per month.

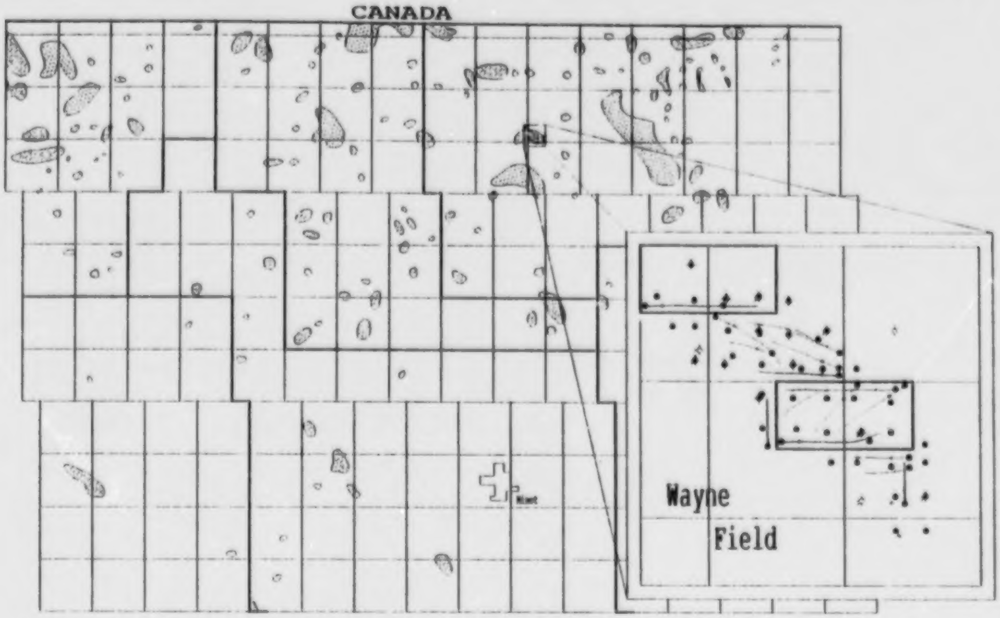
Slide 9

Overbalanced vs. reduced head mud systems – By going to reduced head mud systems, GeoResources, Inc. was able to significantly improve the performance of their horizontal wells. The first well (Oscar Fossum H1) was drilled with an overbalanced fresh water base mud. The second well (Oscar Fossum H2) was drilled with native crude. The remaining three wells (Oscar Fossum H3 & H4, and Ballantyne-State/Steinhaus H1) were drilled with nitrified native crude. The lower curve on the plot is the Oscar Fossum H1 projected out to 120 months. The upper curve is the average of the four Horizontal wells drilled with reduced weight muds.

Slide 10

Economic Summary – A comparison of the overbalanced vs. reduced head mud systems shows a significant improvement in economic returns. This slide details the Net Presents Value (NPV) for the Oscar Fossum H1 drilled overbalanced and the average NPV for the four horizontal wells drilled with reduced head mud systems. By reducing mud weight, formation damage was reduced and NPV was increased by another $750,000 for each additional well drilled.

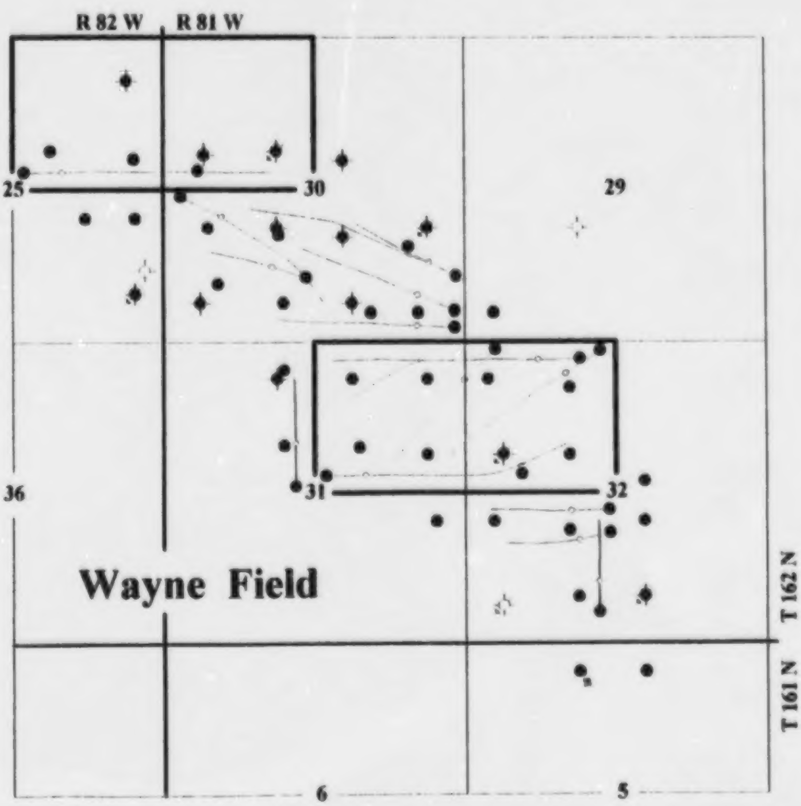
Slide 1



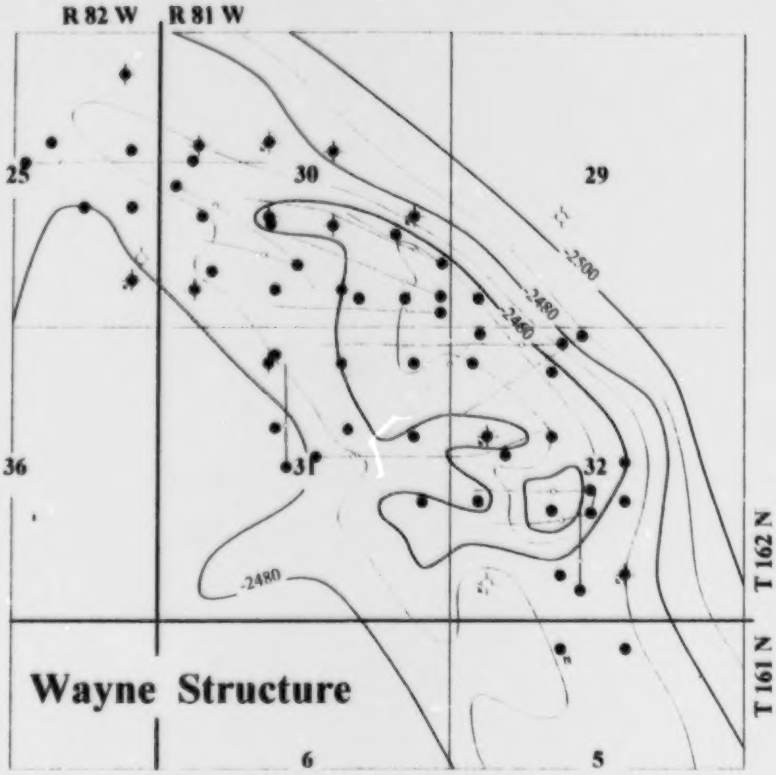
Location Map

NE Flank of the Williston Basin

Slide 2



Slide 3



Wayne Structure

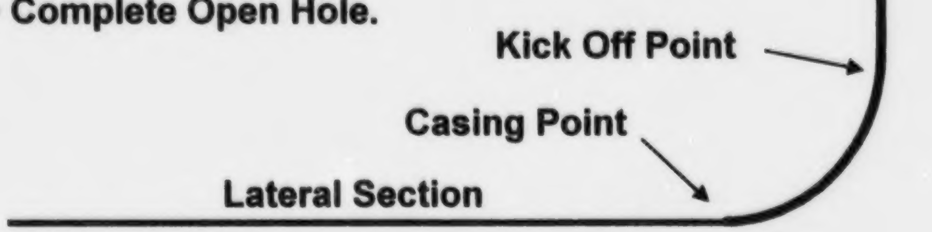
Slide 4

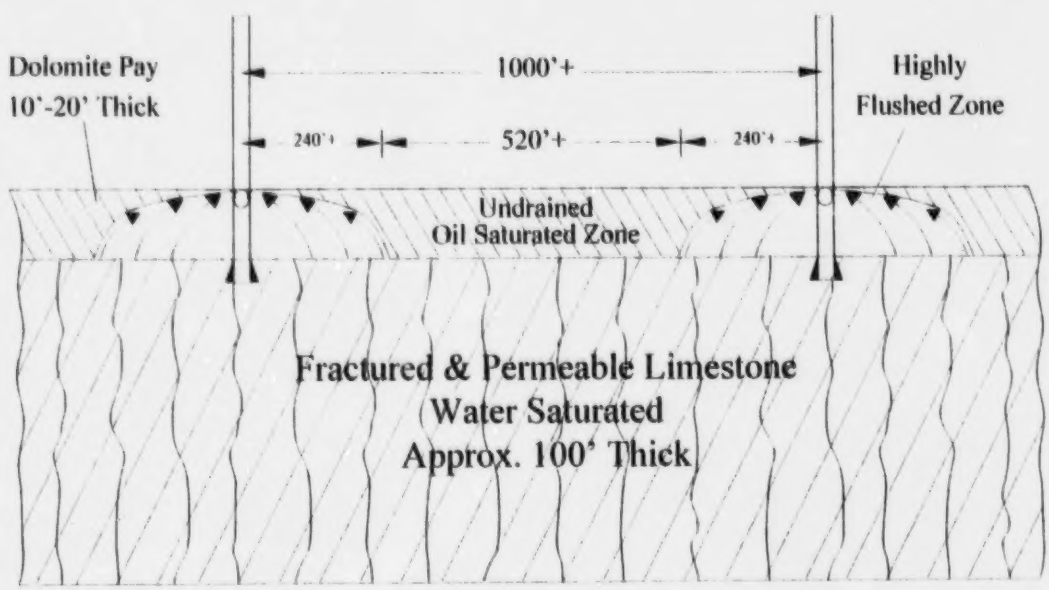
WAYNE RESERVOIR PARAMETERS

• Rock Volume	27,600 Acre - Feet
• Porosity	24%
• Permeability	100 md
• Fm. Vol. Factor	1.10 BBL / STB
• Sw	50%
• Oil Gravity	28° API
• Well Spacing	2 Wells / 80 Acres
• Mechanism	Natural Water Drive

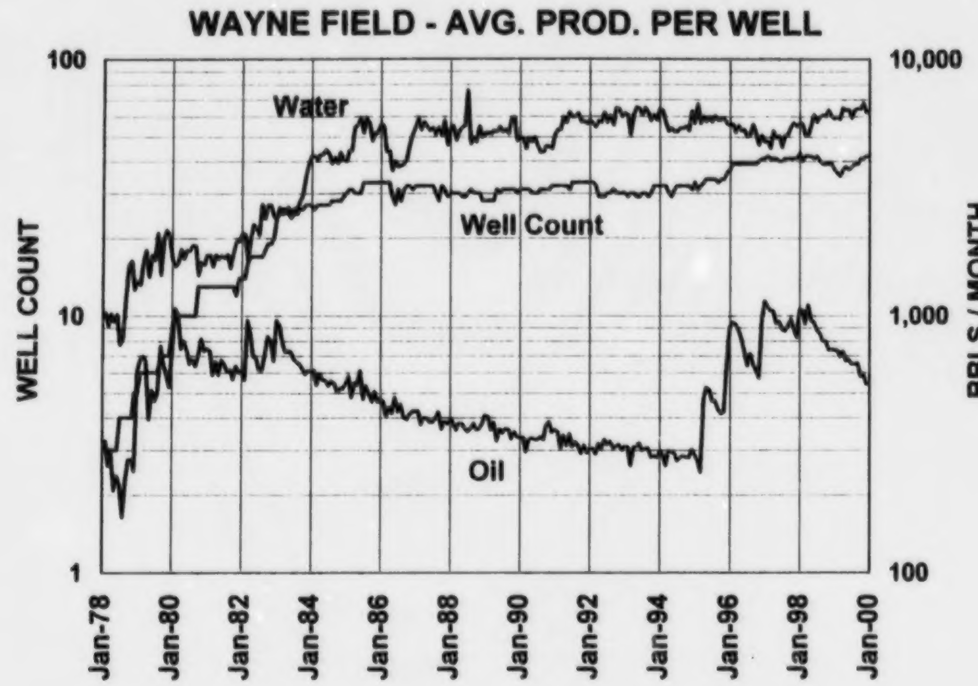
Drilling Sequence

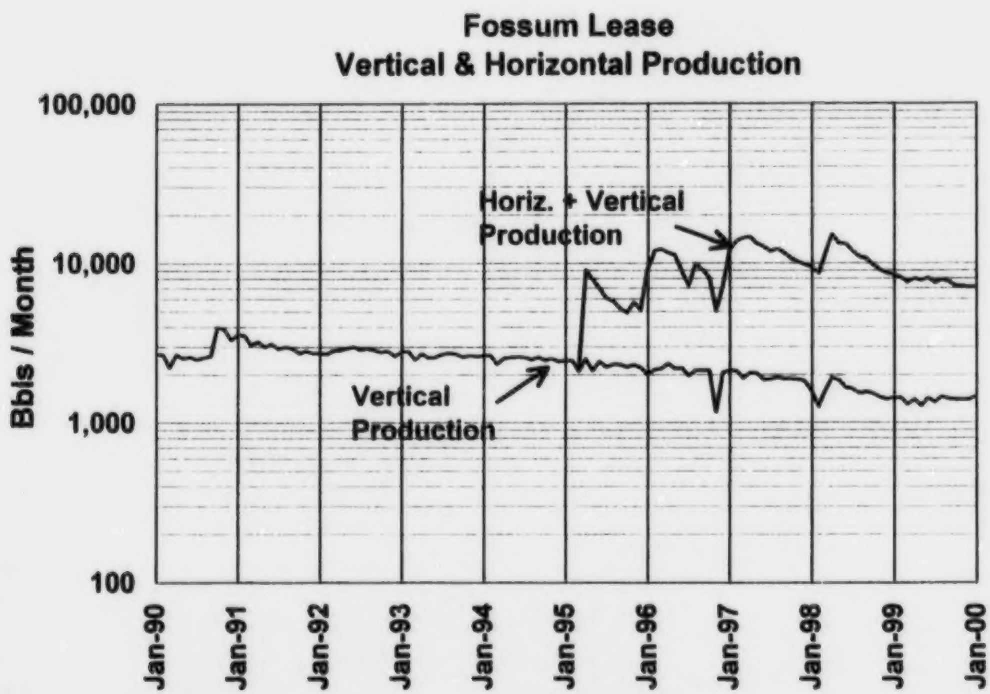
- Drill to Kick Off Point (8 3/4").
- Trip Out. Re-enter With Build Assembly.
- Drill Curve (9° / 100').
- Ream And Clean Hole.
- Set 7" Production Casing.
- Re-enter To Drill Lateral Section (6 1/8").
- Complete Open Hole.

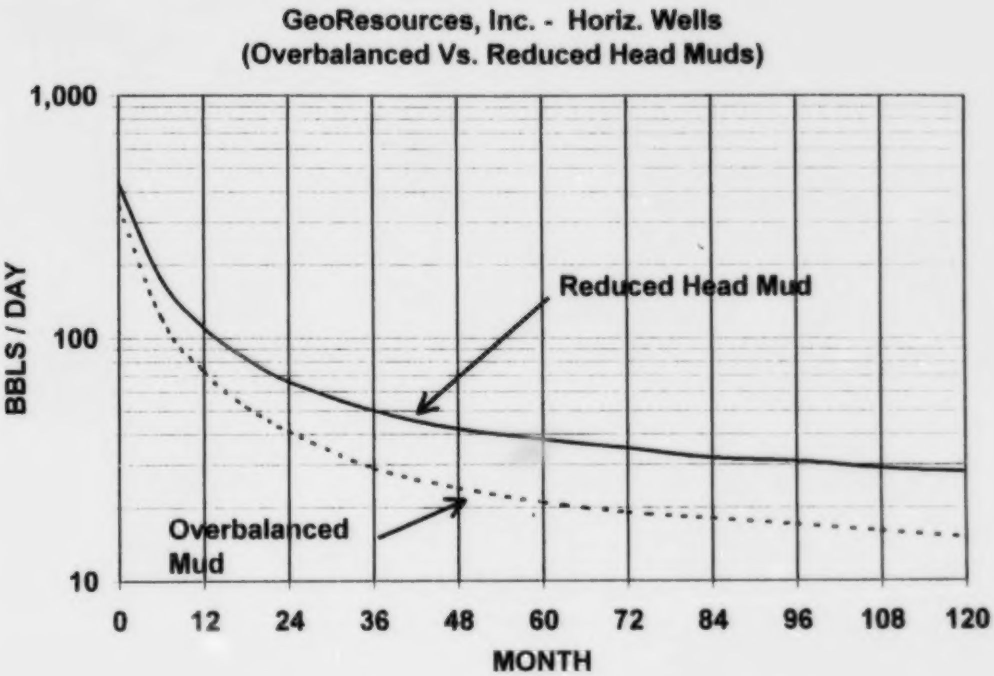




Water Coning Model
for Wayne Field


WAYNE FIELD - AVG. PROD. PER WELL
100
10
1
10,000
1,000
100
WELL COUNT
BBLS / MONTH
Water
Well Count
Oil
Jan-78
Jan-80
Jan-82
Jan-84
Jan-86
Jan-88
Jan-90
Jan-92
Jan-94
Jan-96
Jan-98
Jan-00


Fossum Lease
Vertical & Horizontal Production
100,000
10,000
1,000
100
Bbls / Month
Horiz. + Vertical Production
Vertical Production
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00



Slide 10

Economics

Overbalanced Vs. Reduced Head Muds

Oil Price = $18 / Bbl

Discount Rate = 10%

	Overbalanced	Reduced Head Mud
Disc. Cash Flow	$1,750,000	$2,750,000
Drilling Cost	$500,000	$750,000
Net Present Value	$1,250,000	$2,000,000

Eighth International Williston Basin Horizontal Well Workshop

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O

The Magnitude and Rate of Past Global Climate Changes

John P. Bluemle
North Dakota Geological Survey

The magnitude and rate of past global climate changes

John P. Bluemle
North Dakota Geological Survey
600 East Boulevard Ave., Bismarck, ND 58505-0840

Two colleagues and I undertook to evaluate the validity of several presumed facts and popular and political truisms relating to global climate change (slide 1). We set out to evaluate the following premises:

1. We are in a warming trend
2. The rate of warming is unusually high
3. This warming is the result of humans burning fossil fuels emitting carbon dioxide; that is, the warming is anthropogenic.

Our approach to evaluating these assumptions, particularly the second and third, was to compare current climatic conditions and trends with past geologic and historic events (slide 2)

We reviewed about 200 published articles to compare analyses of past temperatures and variations with the current warming estimates Of these 200 articles, we cited about 70 in a report we wrote for *Environmental Geosciences*. The first thing we learned was that a lot of research has been done on this subject in the past 30 years, especially during the last decade. Our review of the literature, brief as it was, turned up over 6,000 articles we could have reviewed, if we'd had the time. By now it would be substantially more.

Geologists, climatologists, dendrochronologists, oceanographers, palynologists, and a variety of other scientists – have used many methods to interpret past temperatures and changes in climate in many parts of the world (slide 3). A huge amount of independent research has been done on topics such as the advance and retreat of glaciers, retrieval and interpretation of ice cores from Greenland, the distribution pollen in lake and sea sediments, lichen growth, tree rings, sediment layers in glacial lakes, the composition of sea shells and corals, the composition of cave deposits, and several other topics.

These are some of the kinds of data we reviewed. I'll mention just a few of the conclusions we derived from each – simply to give you a "flavor" of the kinds of information that are available.

Studies of varying silt content of lake sediments in Norway and Sweden show how glaciers advanced there between about 6,700 and 6,000 years ago (slide 4).

Evidence from lake deposits in Scandinavia indicate that rapid changes from colder to warmer and back again to colder occurred several times between about 6,500 and 5,000 years ago

Studies of sediment in lakes in southern Norway and Sweden show that sharp cold events took place about 3,700 and 3,000 years ago. Less pronounced cold periods followed – notably one at about 2,000 years ago. During the times between, temperatures warmed briefly. They warmed significantly

at about 1900 years ago. We are speaking of temperatures fluctuating, up and down, between 4 and 8 degrees Celsius, over lengths of time ranging to hundreds of years.

The Holocene sedimentary record beneath the modern Devils Lake in North Dakota indicates repeated flooding and drying, warming and cooling over the past 10,000 years. Similar studies have been done on Great Salt Lake with comparable results.

The character and distribution of glacial sediments depends on what the glacier is doing. Here we see the glacier Vaktpostglaciären in Lapland (slide 5). It is currently shrinking and has receded from the moraines it deposited in the early 18th (check this) century. The shrinking glacier is a result of a warming climate in its area of regimen. The glacier has advanced and receded many times throughout it's history.

Pollen studies in Norway indicate that forest stands of elm and birch there reached a maximum limit about 6,000 years ago (slide 6). Pollen records show that temperatures then were about 4 degrees Celsius warmer than they are today in that area.

Other pollen studies suggest that northern Europe had a warm – a Mediterranean-like – climate between 1,900 and 1,400 years ago.

Where it can be used, dendrochoronlogy – the study of tree-growth rings – can provide a very accurate and detailed record of the climate (slide 7). The dendrochronologic record doesn't go back as far as the pollen or sedimentologic records.

The dendrochronology of Scandinavia has been worked out in great detail (thanks in large part to one of my co-authors, Wibjörn Karlén). Dendrochronologic studies show that the climate there was cold – colder than today – between about 1,200 and 1,100 years ago. They show that it warmed significantly between about 1,100 and 700 years ago.

On this side of the Atlantic – and nearer the present day – dendrochronlogic studies verify that temperatures from 1961 until 1990 in Alberta in the vicinity of the Columbia Ice Field were the warmest they had been there in 800 years.

I mentioned lichenometry earlier – lichenometry is a technique that measures the diameter of lichens. Dates obtained using this technique are quite precise for the Little Ice Age, but less so for earlier moraines. Lichenometry dates in northern Sweden indicate that early and mid-Holocene glacier fluctuations were extensive.

An increase in air temperature results in increased evaporation of water so that the isotope oxygen 16, a lighter atom of oxygen, is preferentially evaporated (slide 8) This increases the relative concentration of oxygen 18. Oxygen in sea water is then combined by marine organisms into shell or skeletal structure. As a result, the ratio of the two isotopes can be used as a proxy measurement of temperature.

Studies of ice cores from Greenland (the American "Greenland Ice Sheet Project II" and the European

study, the "Greenland Ice-Core Project") have resulted in a remarkably detailed record for the past 250,000 years, but especially for the last 12,000 years.

Oxygen isotope data from sediments from Scotland indicate temperature cycles there had less variability, both in frequency and temperature differential before about 2.4 million years ago than they have since then. Since about 750,000 years ago in particular, there has been a dramatic increase in temperature variability. Most authorities relate this to the onset and cycling of glacial and non-glacial conditions.

Nearer to the present, isotopic data indicate a cooling cycle that culminated in Britain about 18,000 year ago. Warming followed that and resulted in the melting of the glaciers. The warming was interrupted during the Younger Dryas cooling event (11,000 to 10,000 years ago). Following the Younger Dryas, a significant warming event is recorded in the isotopic record from Scotland.

Oxygen isotope data from sea-floor sediments beneath the Sargasso Sea, an area of the southwestern Atlantic Ocean known for calm winds and few currents, have resulted in a 3,000 - year history of ocean temperatures from that area (slide 9). They show generally cooling temperatures from 3,000 to 1,500 years ago, warming between 1,300 and 800 years ago – the Medieval Warm Period – and cooling during the Little Ice Age between 300 and 200 years ago.

A little more on the Greenland ice cores (slide 10): This slide shows three curves derived from the Greenland Ice Sheet Project (these curves are from Alley & others 1997 paper in *Science*). The upper curve shows ice-accumulation rates; the middle curve represents change in temperature, based on $^{18}O/O_{ice}$ ratios; and the lower curve is a methane curve, which represents a direct measurement of greenhouse gas preserved in the glacier ice.

Oxygen isotope analysis of older Greenland ice cores – older than I've shown here – shows that the climate during Eemian time was highly variable. The Eemian is the European equivalent of the North American Sangamon, the interglacial that preceded the Wisconsinan and extended from approximately 135,000 until 110,000 years ago). The oxygen isotope record shows that the climate during the Eemian fluctuated much more than it has during the current interglacial, the Holocene.

On two occasions during the Eemian, temperatures dropped from two degrees Celsius warmer than they are today to five degrees colder in only a few centuries. In one instance, temperatures dropped 14 degrees Celsius in a decade and, within 70 years, rose again to their former level.

Evidence of climate changes is not restricted to geologic data. Study of historical documents reveal how climate changes have affected economics and life (slide 11).

Specific cooling and warming cycles can sometimes be precisely documented. Advances of Norwegian glaciers that affected farmland are documented in tax records as far back as the 17th century. At least one glacial advance in the Middle Ages can be precisely dated this way: A widespread advance of glaciers in western Norway between 1660 and 1700 AD – during the Little Ice Age – is well documented and chronicled by tax records. There are also excellent records from the Alps in

central Europe.

Historical records from Iceland indicate that, from the beginning of colonization in 870 AD until at least 1200 AD, glaciers were more restricted than they are now – temperatures were warmer than they are today. During that time, farms were built in locations that were later overrun by advancing ice early in the 18th century. Some of these areas remain ice-covered today. By and large though, glaciers in Iceland are currently retreating.

During the height of the Roman Empire, from about 50 to 400 AD, Arctic sea ice virtually disappeared near Iceland and southern Greenland. During that time, Viking voyages of discovery, colonization and trade in the North Atlantic reached their peak.

Another interesting example: In 1969, the research submarine Alvin located a Clovis-age midden on the Atlantic continental shelf. The site is now submerged beneath 43 meters of water. It was flooded by rising sea level due to melting glaciers at the beginning of the Holocene.

Direct instrumental measurements indicate that the average temperature at the Earth's surface increased about 0.8 of a degree Celsius from 1866 until 1998 (slide 12). During that time, the concentration of carbon dioxide in the atmosphere increased from 280 to 353 parts per million volume. Because this period of time very nearly coincides with the Industrial Revolution, the supposition arose that the warming was caused by human activities.

Most of the warming, however, took place before most of the increase in carbon dioxide occurred. Statistical analyses of the climate record since 1860 show that significant interannual and interdecadal variability occurred during the recorded period. This suggests, or at least raises the possibility that the warming had causes other than an increase in greenhouse gases alone.
Another point I'd like to make relates to the scale of all of this. This graph shows an overall increase in temperature from13.8 degrees Celsius in 1866 to 14.6 degrees in 1998 – a total rise of 0.8 of a degree Celsius. The IPCC currently projects an additional increase of 2.0 degrees Celsius over the next century (they have been lowering their estimate every few years). Compare the measured and projected changes to those I've just been describing. They pale by comparison.

All of the evidence we gathered for our study indicates that climatic changes occur over widespread areas. They occur again and again; they can be large or they can be small. They are both long-term and short-term.

Our review of the literature turned up dozens of temperature curves that various researchers have drawn for various specific study areas or for the whole earth. Their curves characterize periods of time ranging from very short-term to extremely long-term. Here's an example of a long-term curve for central Europe, the beginning of the Tertiary to the present.

This diagram shows that temperatures in central Europe over the past 60 million years dropped about 15 degrees Celsius to the beginning of the Pleistocene (slide 13). They then fluctuated downward another 12 degrees during glacial events and re-gained that 12 degrees during each of the interglacials.

Compiling an accurate, integrated time/temperature curve is a difficult task. Relative rate and magnitude of change are fairly easy to determine. Precise paleothermometry is somewhat trickier. Distinguishing between local weather and climate is difficult even today (certainly, many in the media have difficulty doing it). As I said, it is not easy to draw an accurate curve for even a short period of time, and it is even harder for longer periods of time.

I'll show a diagram I drew to illustrate this point (slide 14). This slide integrates the combined effects of precipitation, temperature, and evaporation for Devils Lake. The Devils Lake watershed is a closed 9,900-square-kilometer drainage basin in northeastern North Dakota. The curve shows a significant highwater stand that very nearly coincides with the Medieval Warm Period and a low-water stand that coincides with the Little Ice Age. It is impossible, of course, using only this Devils Lake data, to reach finite conclusions about worldwide climate and paleotemperatures or, for that matter, to know the effect of these factors on even an area as localized as northeastern North Dakota.

This is a generalized, global, time/temperature curve we drew. It is based on careful, although subjective, analysis of everything we compiled during our study (slide 15). We tried to give due consideration to all the data we collected and in some cases this resulted in contradictions. As one person who criticized our paper said, this is an entirely non-reproducible curve and is therefore not true science. We realize that.

Even so, I offer it to you as just one qualitative attempt to show how the earth's temperature has varied through Holocene time. You'll notice that the curve is quite generalized in places where we had insufficient data to complete the curve. It's likely that, if we had the time to look at a few hundred more of the references that we weren't able to review, we could fill in at least some of the blanks.

Here are some of our conclusions (slide 16):

1. Our most important conclusion is simple: climate is in continual flux. The average annual temperataure is always either rising or falling and the temperature is never stable for a long period of time.

The Holocene Epoch, which we are currently enjoying (I say enjoying because the alternative is probably and ice age!) has been a remarkably stable period of time, with few of the extremes of rising or falling temperatures that were common during the Wisconsinan and the earlier Pleistocene glacial and interglacial periods. Nevertheless, the Holocene was – and still is – a time of fluctuating climate.

2. A corollary: The amount of change, in temperature and other climatic factors, experienced during the past 30 or 50 years has been much less than previous changes. Furthermore, natural variability in temperatures in the past <u>has been demonstrated to far exceed any supportable estimate of current or predicted human-induced variability</u>. Geologists who study past climate variations understand that current climate warming projections fall <u>well within</u> the documented natural variations in past climate.

3. A third conclusion: Observed climatic changes have occurred over widespread areas, probably on the global scale (although the effects have varied greatly from area to area.

4. All previous changes in the climate have occurred without human influence. It can be expected that, irrespective of any present or future anthropogenic influence, global temperatures will continue to fluctuate. Currently, global temperatures are rising. Many scientists think they will continue to rise in the short term.

5. We can't determine whether we are currently seeing any anthropogenic influence on the climate. Climate changes must be judged against the natural climatic variability.

6. Having said that, it's still my opinion that, up to now at least, there is exactly zero reliable scientific data supporting the claim that the world is warming as a result of human-caused greenhouse gas emissions. That is – to use the jargon – there is no "discernable influence" that can be identified as having been caused by humans.

7. Attempts to engineer Earth's very complex climate before understanding natural controls on climate, if they are not impossible, may be quite dangerous, to say nothing of being economically infeasible.

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THE MAGNITUDE AND RATE OF PAST GLOBAL CLIMATE CHANGES

John P. Bluemle, Joseph M. Sabel, and Wibjörn Karlén

Statement of problem

What has the past global climatic variability been in magnitude and rate?

Kinds of data

Sedimentology	Palynology
Dendrochronology	Oxygen isotope ratios
Ice core evidence	Anthropologic evidence
Direct measurements	Historic evidence

Sedimentologic record

- Glacier advances: 6,700 to 6,000 years ago
- Warmer punctuated by cold: 6,500 to 5,000 years ago
- Significant cooling: 3,700 to 3,000 years ago
- Other cold episodes: 2,000 years ago
- Significant warming: 1,900 years ago

Palynologic record

- Northern Norway: warmer by 4° C at 6,000 years ago
- Northern Europe: Mediterranean climate, 1,900 to 1,400 years ago

Dendrochronologic record

Colder than today: 1,200 to 1000 years ago
Warming: 1,100 to 700 years ago

Alberta
Warmest in 800 years, 1961 to 1990

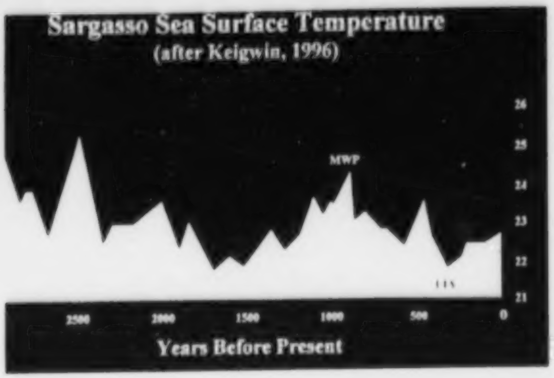
Isotopic record

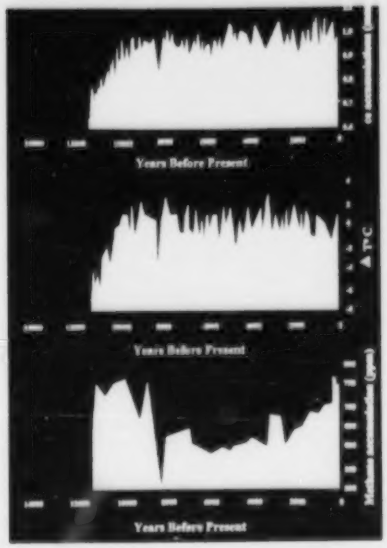
Oxygen isotope ratios: $^{18}O/O_{ice}$

Greenland Ice Sheet Project (GISP):
detailed record for past 250,000 years
Eemian Interglacial (135,000 to 110,000 years ago)
(much more variable than Holocene)

Scotland:
temperatures quite stable prior to 240,000 years ago
temperatures much less stable after 75,000 years ago

Sargasso Sea:
general cooling 3,000 to 1,500 years ago
warm period 1,300 to 800 years ago
cooling from 300 to 200 years ago





Historical and Anthropological record

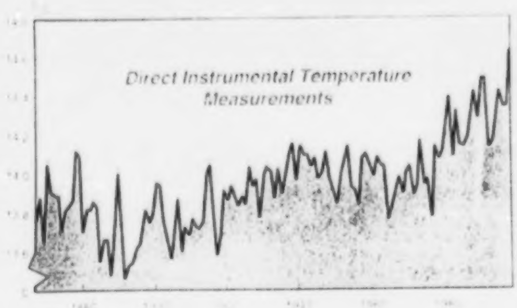
Glacial advances in 17th century cut farm revenues

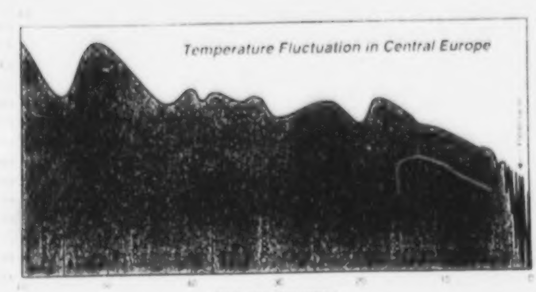
Warm from 870 to 1200 AD

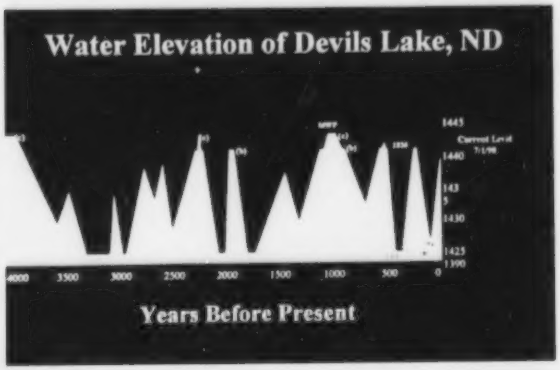
Farms overrun by glaciers during 18th century (still beneath the ice)

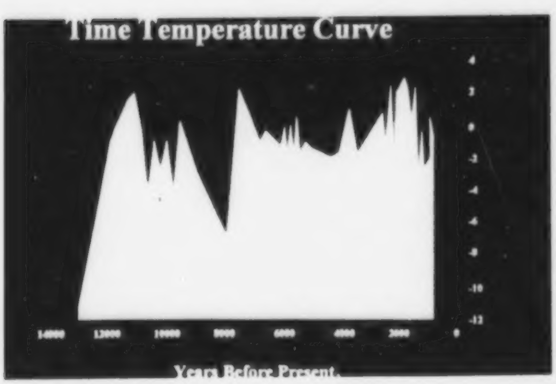
Clovis-age midden on Atlantic shelf

Now submerged in 43 m of water









Conclusions

- Climate is in flux
- Current rate of change is well within previous limits
- Climatic changes have occurred on a global scale
- Anthropogenic influence has not been established
- Climate changes must be judged against natural climatic variability

P

An Affordable Telemetry Solution

*Michael Monea
Flatland Exploration

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SiteLink

An Affordable Telemetry Solution

Micheal Monea (Flatland Exploration)
Don Lang (SiteLink)

The dynamics of the oil and gas industry lend themselves to the application of technology that can be used to optimize production and add greater value to the activities of Stakeholders. Most operation managers claim that their greatest challenge is for their personnel to access timely data in a cost effective manner.

Some of the major companies have successfully applied SCADA Systems (Supervisory Control and Data Acquisition) as a tool to help increase productivity, reduce the costs associated with environmental issues, improve personal safety and enhance other value added activities. The costs and infrastructure associated with typical SCADA Systems are generally uneconomic for oil and gas companies.

The Site.Link concept is to provide a low cost, simple, end-to-end solution to allow a customer to access data 24 hours a day, seven days a week, all via the internet. A typical site would be configured with an RTU (Remote Terminal Unit) and have a variety of sensors connected by wire or spread spectrum. These sensors gather pertinent data, store the information in the RTU and then send the data wireless via a CDPD Modem (Cellular Digital Packet Data) network to a host server. The information is recorded every hour, thus giving the company 24 reports or readings each day. This allows operators and engineers to view real-time data and trends.

This information/data is then delivered to the end user by the internet, a common tool that people are familiar with and can access anywhere; at home, the office, or while travelling. This gives personnel authorized with security codes and an internet account the ability to monitor and control production from anywhere in the world.

In addition to regular reporting, a customer can choose the option of Fast Polling (perhaps on a new high volume well or after a repair to a problem well). With this feature a 5 minute sample rate is recorded and reported to the customer hourly over a 24 hour period. A customer would designate how long (i.e. 2-3 days) they with Fast Polling to run. Also, a snap shot or remote poll can be requested which gives the customer real time data at anytime of the day or night.

Over and above data capture, the system can be programmed for alarm notification in the event an emergency situation is detected. These alarms are generated based on user defined thresholds and will notify appropriate personnel via pager, email, fax or actual telephone call.

Some of the monitoring options available in Site.Links System include:

- pumpjack on/off status and strokes per minute
- monitor casing pressure
- monitor tank levels
- detect stuffing box leaks
- monitor torque or motor load
- measure various temperature and pressure readings
- measure oil, gas or water flow volumes

There is also the ability to remotely stop and start the well. Sites that are not powered by electricity can be supplied power to run the RTU, with a solar panel.

Tangible benefits associated with this system could include:

- increased production
- spill avoidance
- reduced downtime
- reduced equipment failure
- reduced operating/maintenance costs
- reduced driving time
- lower vehicle costs

In addition, real-time access to data allows business decisions to be made based on accurate and current information. Also Site.Link offers a "Common Platform", in other words, properties can be sold or traded between companies and access to information gathered at the sites can be transferred to the new owner by issuing a new confidential password for the internet access.

This concept can be utilized at a single well site, be it a problem or high volume well, a remote terrain restricted site, an environmental sensitive location, battery sites or on a multi-well basis, depending on customer needs and requirements.

Process Control or SCADA Systems in the oil and gas industry have been in place for years. Major oil and gas companies have been leaders in the use of this technology, which is continuously evolving. New solutions to old problems are constantly being developed. Current monitoring technology products are constantly being refined and improved, and because of increased competition are becoming more affordable. The improved economics should encourage more oil and gas companies to take advantage of these products. The Site.Link concept will provide and end to end solution. We acquire, install and maintain the equipment, we also collect, transmit and store the data. The customer accesses the information where, when and how they choose.

Q

Geosteering in Targets with Subtle Gamma Ray Character Utilizing True Stratigraphic Position Modeling (TSPM)

Kenneth Bowdon
Bowdon Energy Consultants

Geosteering in Targets with Subtle Gamma Ray Character Utilizing True Stratigraphic Position Modeling (TSPM)

Kenneth Bowdon, Bowdon Energy Consultants

The increased utilization of horizontal drilling has changed the role of the geologist in drilling operations. The difference is as profound as when comparing a two dimensional painting to a three dimensional sculpture. The geologist, in the past, need only plan a two dimensional location consisting of a spot on the surface and a depth to the reservoir. He would then pass this location to an engineer who would drill the well. When all wells drilled were either vertical or slightly deviated the geologist provided little input while the well was drilling. He would occasionally show up on location to pick a coring point, casing point, or to log the well once drilling was completed. The role of the geologist is significantly different for a horizontal well. He must be an integral part of any horizontal drilling team. The prefix of the term **geo**-navigation indicates the important part subsurface geology must play in any successful horizontal venture.

The objective of a horizontal well is to maximize exposure of the wellbore to the reservoir. As a result, the geologic framework of the reservoir must be the guiding principle for the planning, drilling and completion of any horizontal well. A horizontal well will most likely not perform to its maximum potential if the wellbore does not stay in the reservoir. Horizontal wells should be planned and drilled under a new paradigm. Most horizontal wells should be drilled using the **geologic framework as the primary reference point**, not TVD. In the early days of horizontal drilling, TVD was the primary point of reference when navigating a horizontal well. Today, the successful operator understands that the **relative position of the wellbore to the stratigraphy** is the single most important piece of information needed to maximize the potential for success. This new point of reference is called True Stratigraphic Position (TSP). Many tools and methods are available to assist the geologist in determining this relationship but one of the most useful is the MWD gamma ray log used in conjunction with True Stratigraphic Position Modeling (TSPM).

True Stratigraphic Position Modeling (TSPM)

The most important and basic function a geologist performs in his job is the correlation of logs to determine the stratigraphic position of equivalent points in wellbores. Gamma Ray logs are one of the best lithologic indicators available to the geologist and are used extensively throughout the world to correlate vertical wells. Most operators run an MWD gamma ray log in their horizontal wells as an aid to geo-navigation though many do not utilize these logs to their fullest potential. Many observe only the amplitude of the gamma ray reading to indicate when they are "out of zone" then decide whether to turn the bit up or down to get back in zone. The MWD gamma log must be used for pattern matching within the target if it is to be a significant navigation tool. A visual interpretation of a measured depth MWD gamma ray log in a horizontal well can be very difficult, if not impossible, because of complication of wellbore geometry, structural

complexity, stratigraphic variability, and subtle character changes. To make the MWD gamma log useful, the stratigraphic information must be isolated by zeroing out the structural and wellbore geometry influences to the gamma character.

One method that accomplishes this task is the True Stratigraphic Position Modeling technique. The TSPM method generates a True Stratigraphic Position Log (TSP log). TSPM restores the gamma ray recorded in a horizontal wellbore to its true stratigraphic position, negating structural influence and wellbore trajectory then displays the gamma as if the well were drilled vertically. A True Stratigraphic Position log can be correlated with offset vertical logs and against earlier passes of the horizontal wellbore through the target to determine stratigraphic position, saving valuable time when a change in wellbore trajectory is required. TSPM provides three of the four keys needed to successfully steer a horizontal well.

1. The position of the bit relative to the stratigraphic section. (TSP)
2. The apparent formation dip rate
3. Fault cuts

The fourth key, provided by the directional company, is the position of the bit relative to the surface consisting of TVD, north departure, and East departure.

MWD Gamma Ray Resolution.

It is important to note that a gamma log in a horizontal well provides more stratigraphic content than a vertical log in the same area. This phenomenon has been documented throughout the world in more than 70 formations. The primary reason a gamma ray log in a horizontal well is more accurate is that the acquisition speed is very slow. The accuracy of the gamma reading is proportional to the length of time that the sensor is adjacent to the formation. Multiple gamma ray readings must be averaged within the same interval to determine an accurate gamma ray value, therefore, a "raw" or unfiltered gamma ray log does not accurately characterize the stratigraphic section. The second reason a MWD gamma log in a horizontal wellbore is more definitive than one recorded in a vertical hole is related to the inclination of the wellbore relative to formation dip. A vertical gamma log has a bed resolution of 3' to 6' depending upon tool configuration and logging speed. While the 3' measured depth averaging normally still applies to a log recorded in a horizontal well, the stratigraphic resolution is much better because of the low relative angle of the beds to the wellbore. The stratigraphic resolution of a gamma log in a well that is drilled within 2 degrees of the formation is better than 0.1 foot.

Subtle MWD Gamma Ray.

Many formations throughout the world exhibit subtle gamma ray character when observed in vertical wells. The Buda and Georgetown Formations in South Texas have a very subtle but consistent gamma ray character. Many other formations throughout the USA and Canada exhibit a very subtle gamma character yet wells within most of these areas can be correlated within a radius encompassing the average horizontal well.

Likewise, gamma logs in vertical wells show little character through many formations within the Williston Basin in both the USA and Canada. The Red River formation and the Midale formation are good examples in the Williston Basin. The subtle character in these formations, however, is very consistent and can generally be correlated within a 3000' radius. The gamma ray in horizontal wells within the Williston basin shows much more character than the gamma in offset vertical wells. The key to utilizing gamma as a correlation tool in subtle gamma ray areas is consistency of character, not amplitude of the gamma ray values, since appropriate scaling can enhance the amplitude. A visual interpretation of a measured depth MWD gamma ray log with subtle gamma ray character is virtually impossible. The TSP log scaled appropriately, however, can be utilized successfully to steer a horizontal wellbore in these areas.

Summary

Except in the case of a well drilled to alleviate coning, it is more important to know the relative position of the wellbore within the stratigraphic section than to know the depth below the surface. True Stratigraphic Position Modeling provides this information along with formation dip and the location and throw of faults, helping the geosteering team to more accurately navigate horizontal wellbores. TSPM can be utilized in areas exhibiting subtle gamma ray character to successfully steer a horizontal wellbore.

Geosteering in Targets with Subtle Gamma Ray Character Utilizing

True Stratigraphic Position Modeling (TSPM)

OUTLINE

I. The Art of Geo-navigation

III. A New Paradigm

IV. True Stratigraphic Position Modeling (TSPM)

IV. Resolution of the horizontal gamma log

V. Subtle Gamma Ray Character

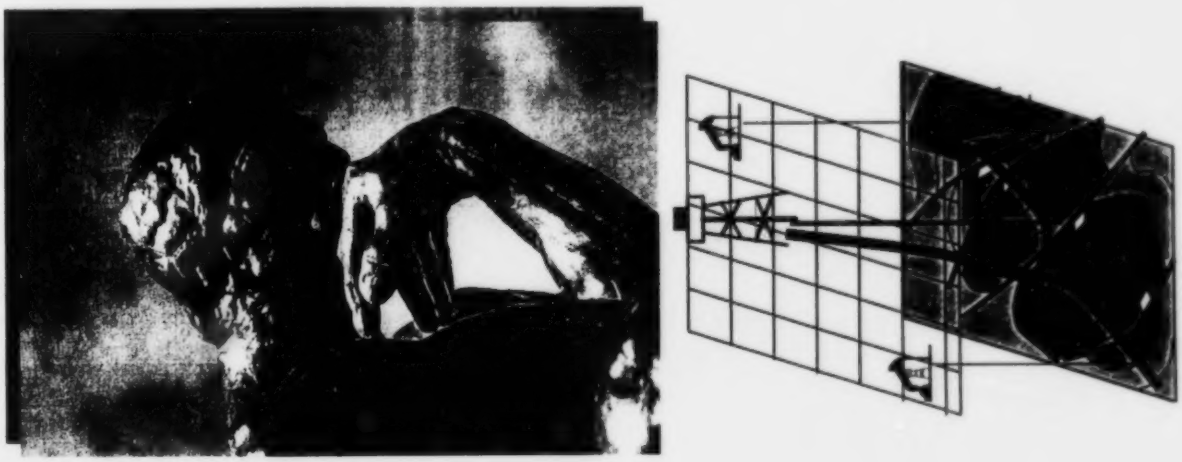
VI. Examples

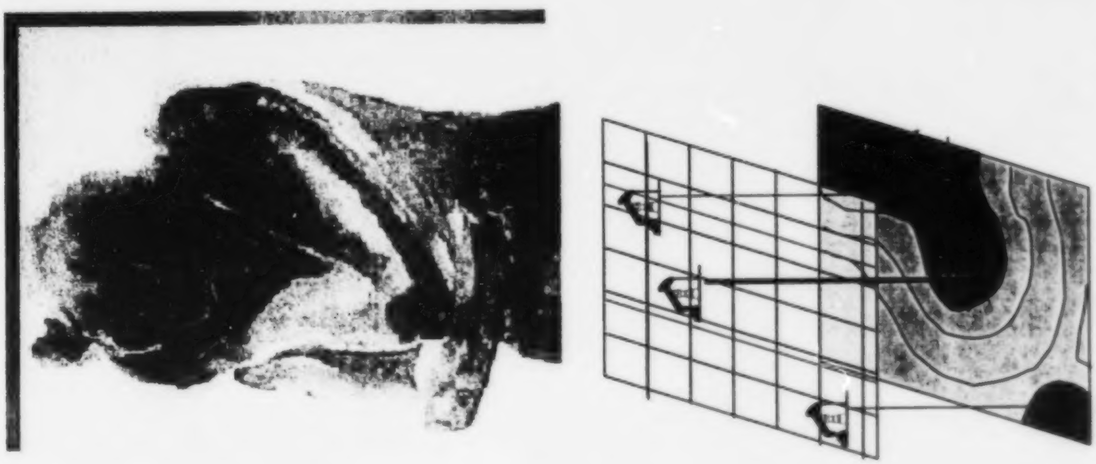
VI. Summary

Geosteering in Targets with Subtle Gamma Ray Character Utilizing

True Stratigraphic Position Modeling (TSPM)

The Art of Geo-navigation





Geosteering in Targets with Subtle Gamma Ray Character Utilizing

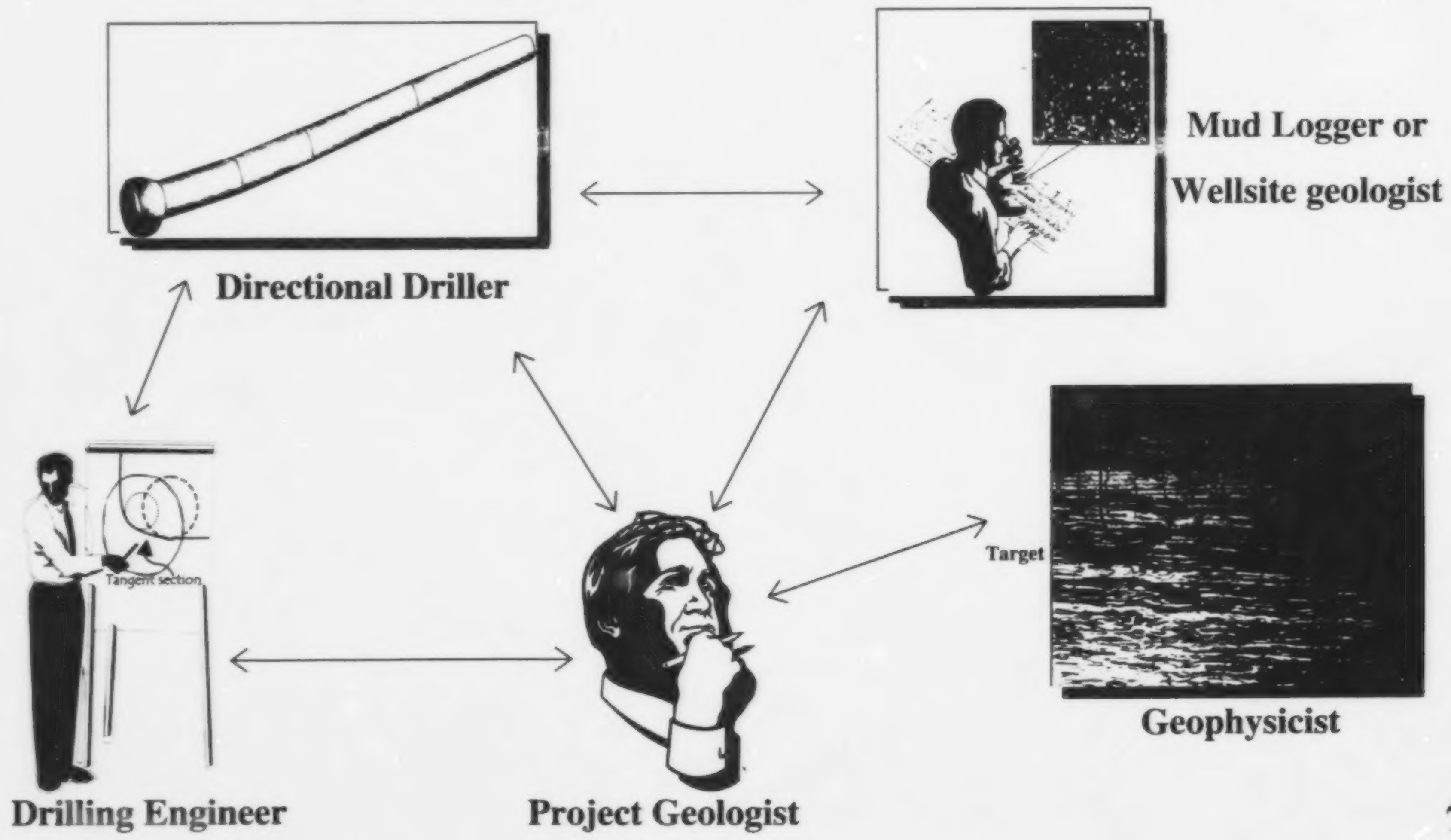
True Stratigraphic Position Modeling (TSPM)

- Steering a horizontal well is like driving a car while looking only in the rear view mirror

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

The Geologist should have an integral role in ***Geo-navigation***



Geosteering in Targets with Subtle Gamma Ray Character Utilizing

True Stratigraphic Position Modeling (TSPM)

Geonavigation

The prefix indicates that the geologic framework must play a significant role when steering a horizontal well

Geosteering in Targets with Subtle Gamma Ray Character Utilizing

True Stratigraphic Position Modeling (TSPM)

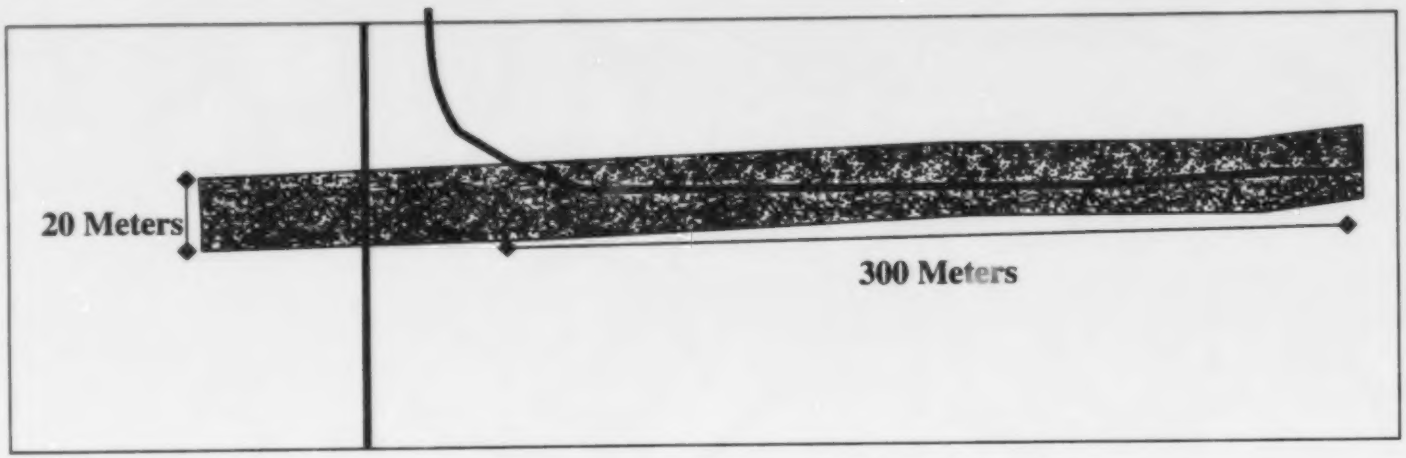
The TSP Paradigm

True Stratigraphic Position

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

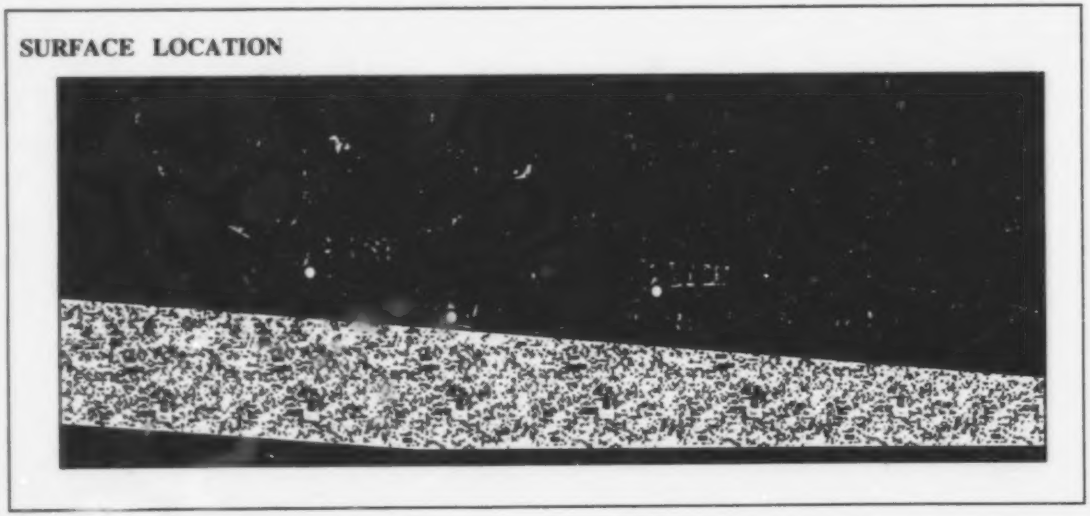
- **The Purpose of drilling Most Horizontal Wells is to Maximize Wellbore Exposure to the Reservoir**



Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

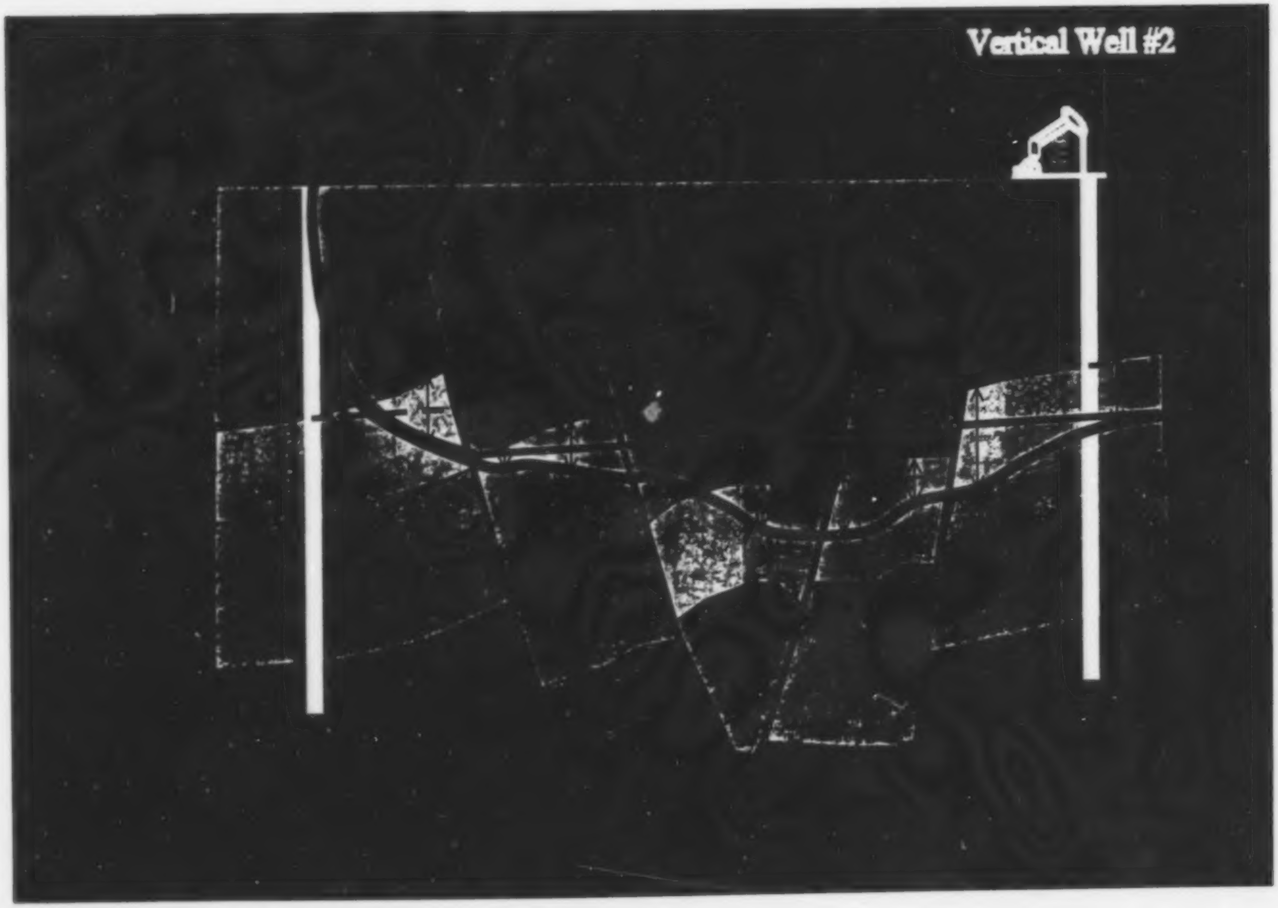
True Stratigraphic Position Modeling (TSPM)
A New Paradigm

TSP is the position of the Wellbore,
relative to a stratigraphic reference point**
within the stratigraphic section.
(i.e. Top of Target)**



Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)
A New Paradigm



Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)
<u>A New Paradigm</u>

Geologic Framework Must be of Primary Consideration when Planning and Drilling a Horizontal Well

Frame of Reference is Relative to True Stratigraphic Position (TSP

- **TVD has No Stratigraphic Content**

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

Drilling a well utilizing the True Stratigraphic Position Paradigm Keeps the wellbore in target because it is a Relative Stratigraphic Approach;

Ties the position of the wellbore to Stratigraphy

NOT

TVD

Geosteering in Targets with Subtle Gamma Ray Character Utilizing

True Stratigraphic Position Modeling (TSPM)

The
TSP Paradigm
Changes the way a horizontal well is navigated

Geosteering in Targets with Subtle Gamma Ray Character Utilizing

True Stratigraphic Position Modeling (TSPM)

True Stratigraphic Position Modeling

(TSPM)

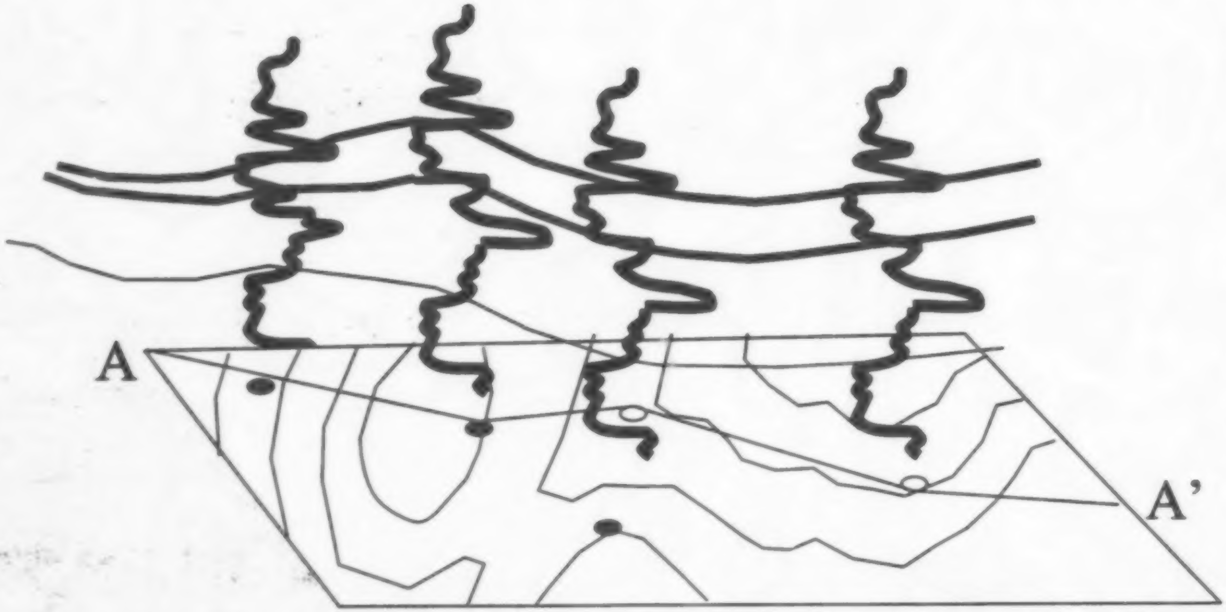
- Concept
- Examples

Geosteering in Targets with Subtle Gamma Ray Character Utilizing

True Stratigraphic Position Modeling (TSPM)

Concept

Correlation of logs: the most basic tool for the geologist



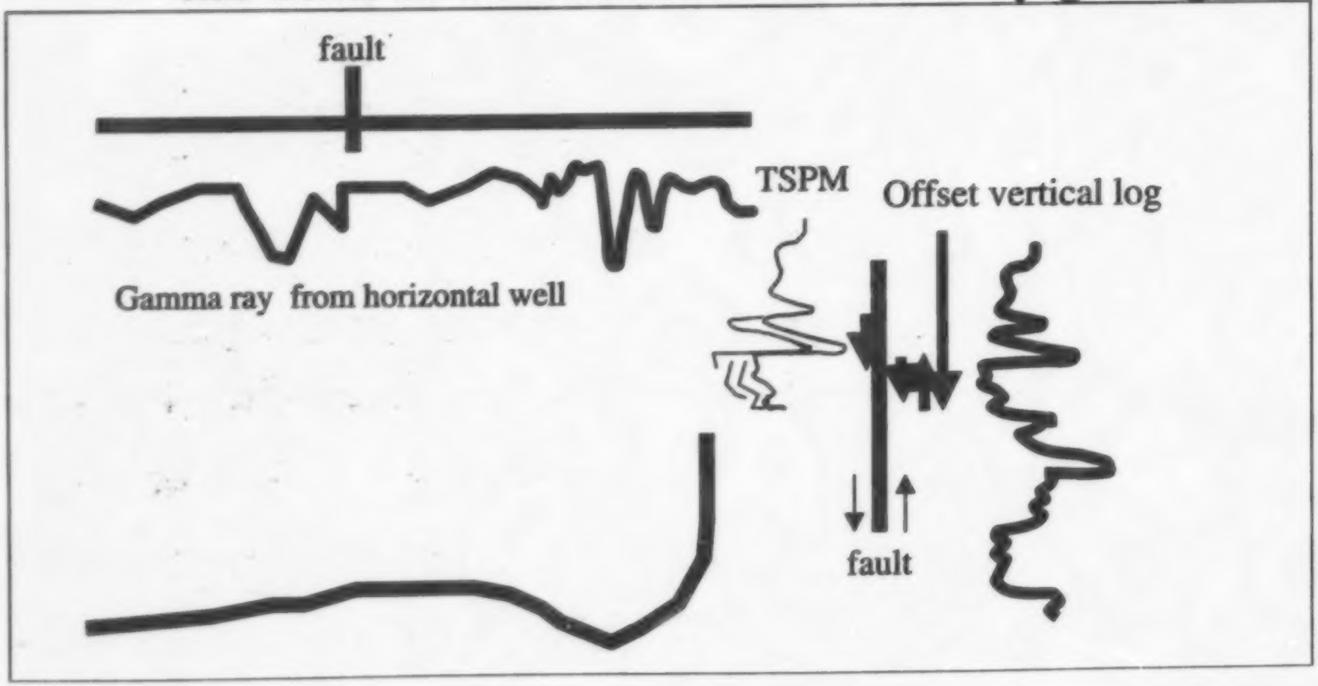
Map and cross-section before horizontal well

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

Concept

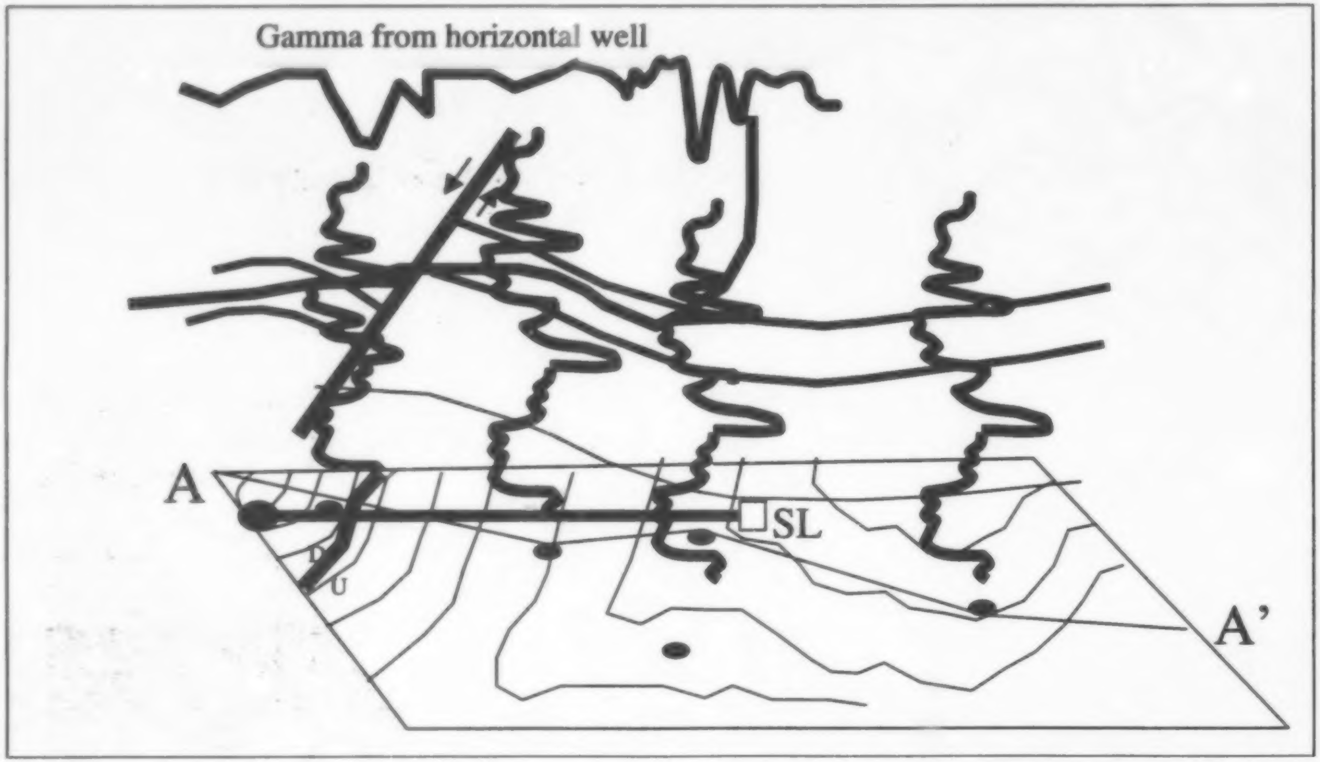
TSPM translates the gamma ray in the horizontal well to its position within the vertical stratigraphic section, thereby presenting the data in a form familiar to every geologist



Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

Concept
TSPM refines the structural and stratigraphic interpretation



Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

Four Keys of Geo-navigation

- **The stratigraphic position of the wellbore**
- **The location, throw, and direction of faults that cut the wellbore**
- **The formation dip rate**
- **The position of the bit in the earth relative to the surface location**

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

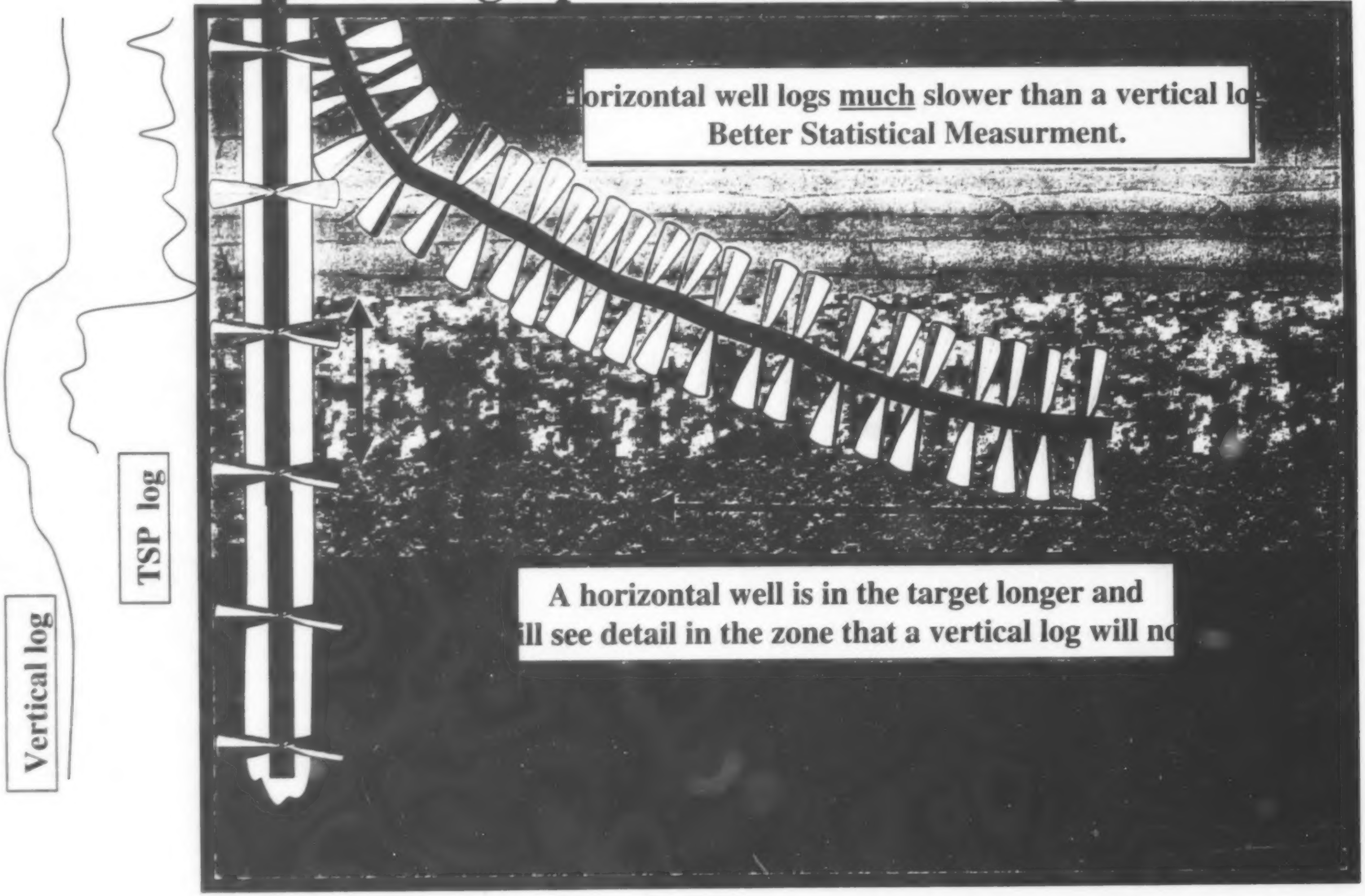
True Stratigraphic Position Modeling (TSPM)

MWD Gamma Ray Resolution

Vertical Versus Horizontal

Geosteering in Targets with Subtle Gamma Ray Character Utilizing

True Stratigraphic Position Modeling (TSPM)



Geosteering in Targets with Subtle Gamma Ray Character
Utilizing
True Stratigraphic Position Modeling (TSPM)

Extract the most from your gamma ray data

- <u>Raw</u> Gamma does <u>not</u> provide more stratigraphic content

- Gamma ray measurements are statistical and must be averaged

- Display gamma data at an appropriate scale

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

Examples

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

Example I
Buda / Georgetown Stacked Laterals

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

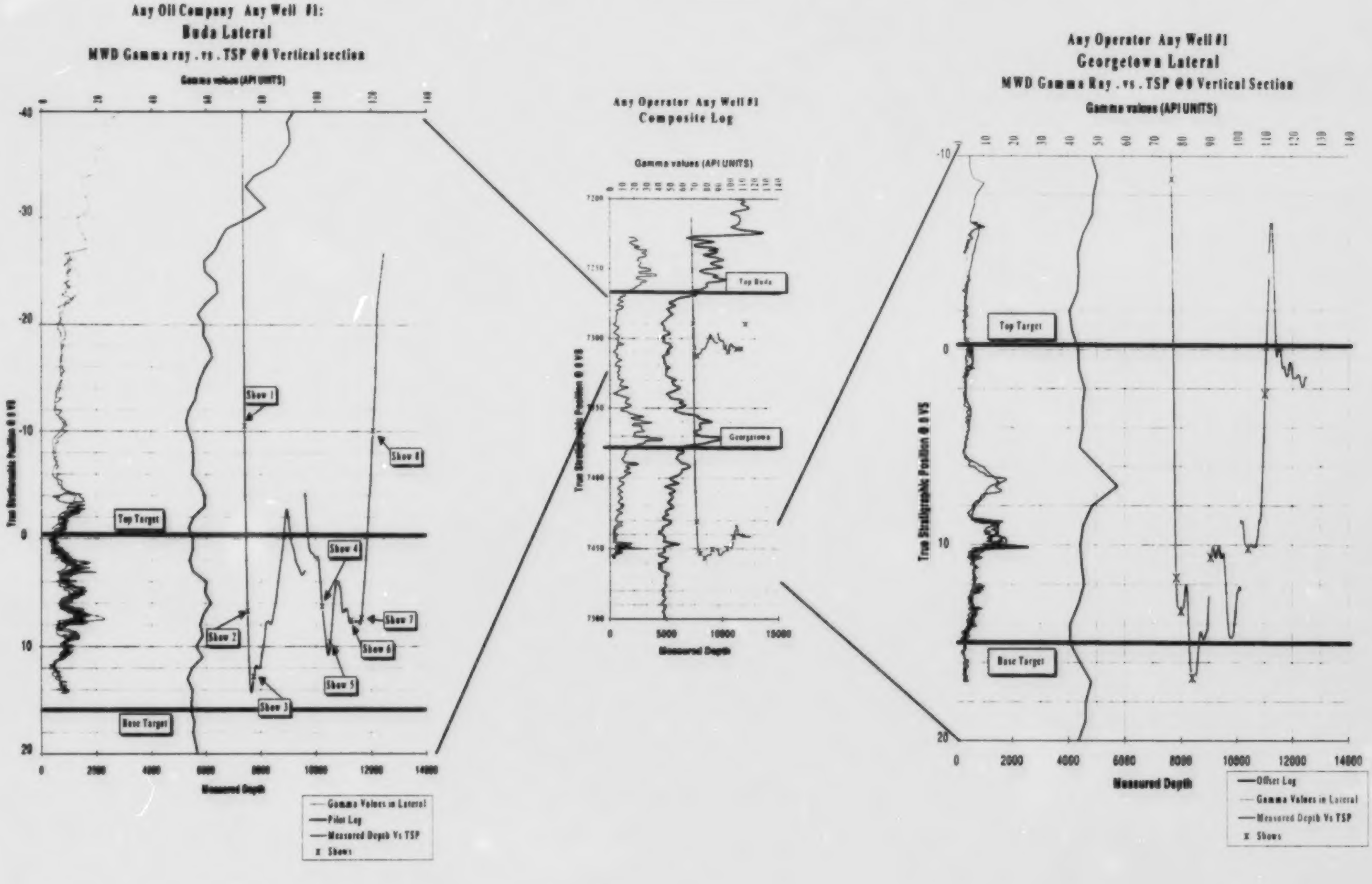
Example I
Buda / Georgetown Stacked Laterals: Texas

True Stratigraphic Position Log displays:

- Horizontal gamma ray translated to True Stratigraphic Posi
- Offset Log
- Path of wellbore relative to stratigraphic position

Geosteering in Targets with Subtle Gamma Ray Character Utilizing

True Stratigraphic Position Modeling (TSPM)



Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

Example I
Austin Chalk: Texas

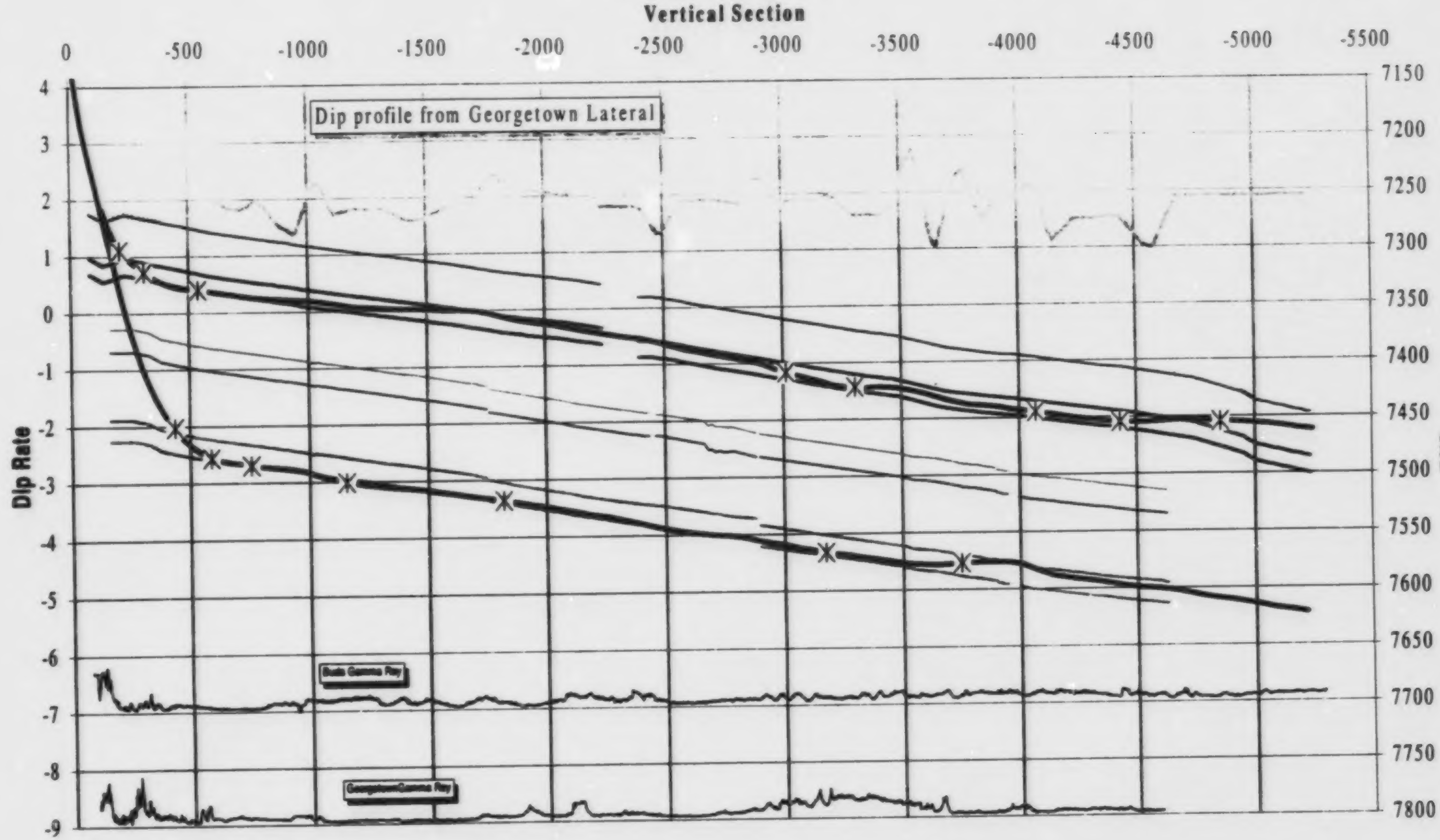
Wellbore Plot displays:

- **Cross-section view along wellbore path**
- **Top and base of target**
- **Gamma ray from horizontal well plotted along the wellbore azi**
- **Continuous profile of the formation dip rate**

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

Any Operator Any Well #1 Buda and Georgetown Laterals
Wellbore plot



Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

Summary

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

Summary

- A New Paradigm Makes True Stratigraphic Position the Reference
- The Geologist Must Play a Crucial Role While Drilling a Horizontal Well
- Subtle Gamma Ray Character can be successfully used for geosteering

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)
Summary

The four keys needed to navigate a horizontal wellbore

Position of bit in earth

Formation dip rate

Stratigraphic position of the bit

Fault identification

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)
Summary

True Stratigraphic Position Modeling
Provides Three of the Four Keys to Geo-navigation

And

Allows the Geologist to interpret Gamma Ray with subtle character

Geosteering in Targets with Subtle Gamma Ray Character
Utilizing

True Stratigraphic Position Modeling (TSPM)

R

Horizontal Exploration of the Mississippian Mission Canyon Formation "Nesson" Zone, Burke County, North Dakota

Paul S. Molnar
Burlington Resources

Horizontal Exploitation of the Mississippian Mission Canyon Formation "Nesson" Zone, Burke County, North Dakota

In 1996, Burlington Resources' teams assigned to the Williston Basin were challenged to find opportunities similar to the successful Red River 'B' horizontal play. The Midale and Nesson reservoirs in Burke County, North Dakota were chosen for several reasons: high porosity/low permeability carbonate targets, proximity to vertical production with flat decline curves, shallow drill depth, log analysis indicating good oil saturations in several zones, and a prospective area large enough to generate considerable upside potential.

The Midale and Nesson zones are members of the upper Mississippian Madison Group. Regional dip is to the southwest. Most vertical production is on broad structural noses which plunge basinward . Total Midale/Nesson pay averages 25' to 30'. The reservoirs are bounded above and below by anhydrite seals.

The Midale reservoir is a very finely crystalline dolomudstone with an average of 22 - 27% intercrystalline porosity. Three porosity zones are separated by two tighter intervals interpreted to represent minor rises in eustatic sea level. Matrix permeabilities are low, generally below 1 md. Net pay in the Midale averages 14' to 18'. Vertical fractures are noted in core descriptions.

The underlying Nesson reservoir is a very finely crystalline fossiliferous limestone. Reservoir rock includes algal wackestones and boundstones with occasional peloidal grainstones. Porosity in the Nesson pay averages 6 - 12%, and includes moldic, interparticle, and intercrystalline. Matrix permeability is low, about 1 md; it is enhanced locally by vertical fracturing, but degraded by anhydrite cement. Net pay in the Nesson averages 6 - 8 feet. A tight skeletal mud limestone, interpreted to represent a minor rise in relative sea level, separates the Nesson reservoir rocks from the overlying Midale.

Vertical wells in the area include: Midale/Nesson fields developed on 160 acre spacing with highly variable EUR's; isolated sub-economic producers; and dry holes (many of which had oil shows on drillstem tests or cores). The variability in production, flat declines, and oil shows unassociated with structural closures all indicate potential for horizontal exploitation. The Nesson was the targeted zone, since it has better permeability and more consistent calculated oil saturations than the Midale. It was assumed that vertical fractures would facilitate drainage of oil (or at least pressure support from gas) downward from the Midale into the Nesson laterals. The initial drilling program included two wells, each with a single Nesson lateral drilled on 320 acre spacing.

Assessment of the first wells drilled indicated one marginally economic well and a sub-economic well. FMI's run in both wells confirmed the presence of vertical fractures (trending SW-NE), and indicated the fractures occurred in swarms and were not evenly distributed. The team looked at the problem in terms of trying to increase recovery efficiency and reduce drilling costs. To do this, the spacing was increased to one well per 640 acres. Casing was set in zone at about 90 degrees. A long lateral across the section

and two shorter sidetracks were drilled in a "bird's foot" configuration, and the formation produced from open hole. The cost per lateral foot was reduced from $250/foot to less than $100/foot. The wells were oriented with the longest lateral NW-SE to maximize the number of fractures encountered.

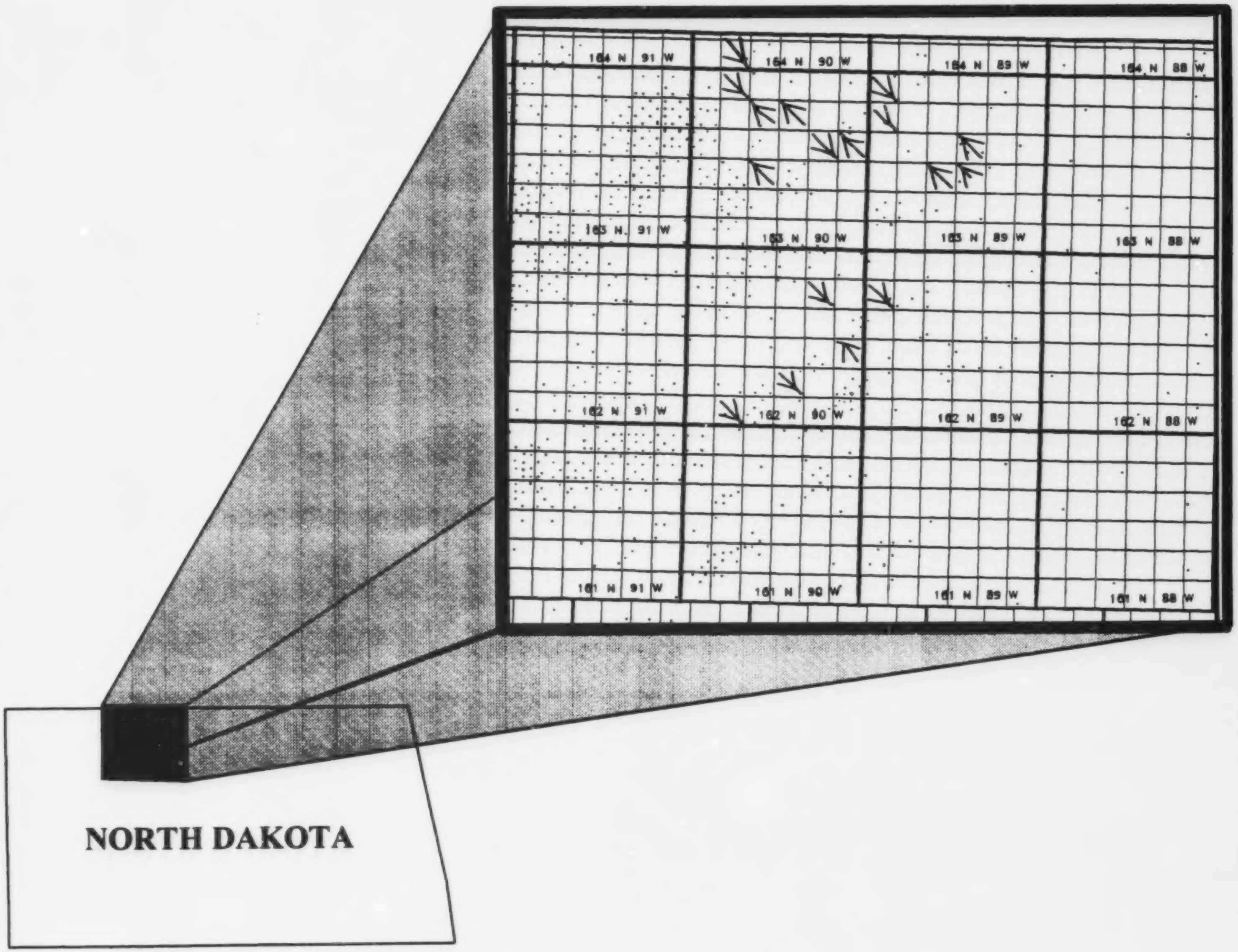
The results were highly variable (maximum daily rates ranging from 123 - 852 BOPD) but still encouraging, based on extrapolating early production rates using decline curve analysis of nearby vertical wells. It was not until well into the program that it was observed that the horizontal wells' hyperbolic decline curves were not flattening with the expected exponent. With lower EUR's and lower oil prices, the drilling program was halted to evaluate new data that had been acquired drilling fourteen tri-lateral wells.

Histograms and crossplots of all relevant data (IP's, EUR's, gas shows, ROP, LWT porosity, footage in/out of zone, sample lithologies, rate of dip change, structural position) were constructed to attempt to identify a method to highgrade well locations. The only relationship observed was between structural position and well performance.

From the play's inception, isochron maps from 2D seismic data and isopach maps from vertical well control were successfully used to locate prospects on broad structural noses. However, the six best performing wells were located on small, tight noses superimposed on the larger, regional structures. Higher depositional energy favored development of peloidal grainstones (relatively high permeability), and the tight structures enhance fracturing. Using this model, two more wells were drilled. Both were drilled on local structures; one is the best well drilled to date in the play, while the other had very poor reservoir development and is one of the poorer wells. An offset to the best well has recently been completed; it appears to be an average well, but it is too early to extrapolate a decline exponent.

In summary, this area exhibited characteristics which suggested it was a likely candidate for horizontal exploitation. Well performance is highly variable, with a broad range of intitial potentials, decline exponents, and estimated recoveries observed. Identifying predictive tools to highgrade drilling locations in this heterogeneous reservoir will enhance continued development.

STUDY AREA



164 N 91 W
164 N 90 W
164 N 89 W
164 N 88 W
163 N 91 W
163 N 90 W
163 N 89 W
163 N 88 W
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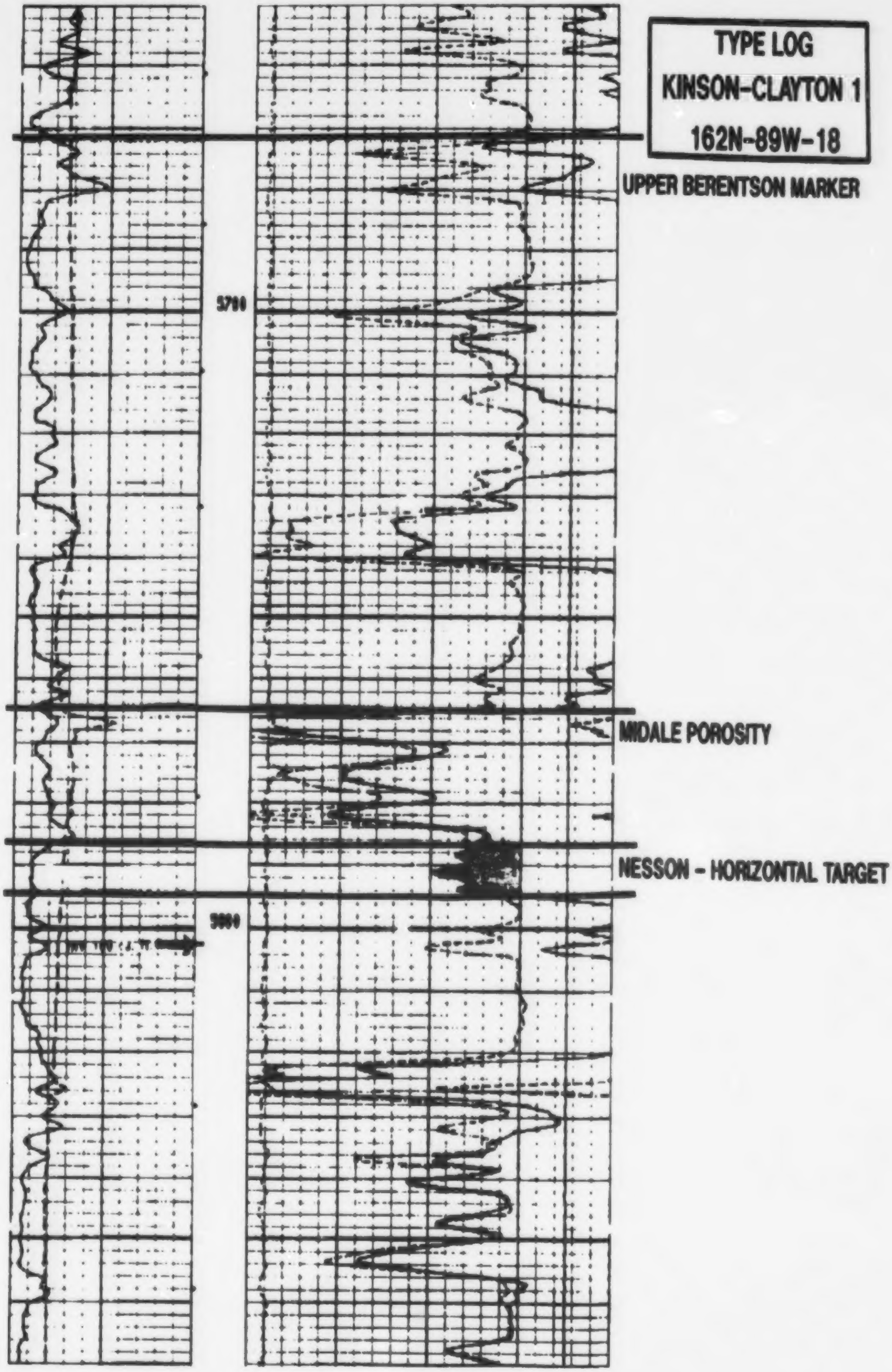
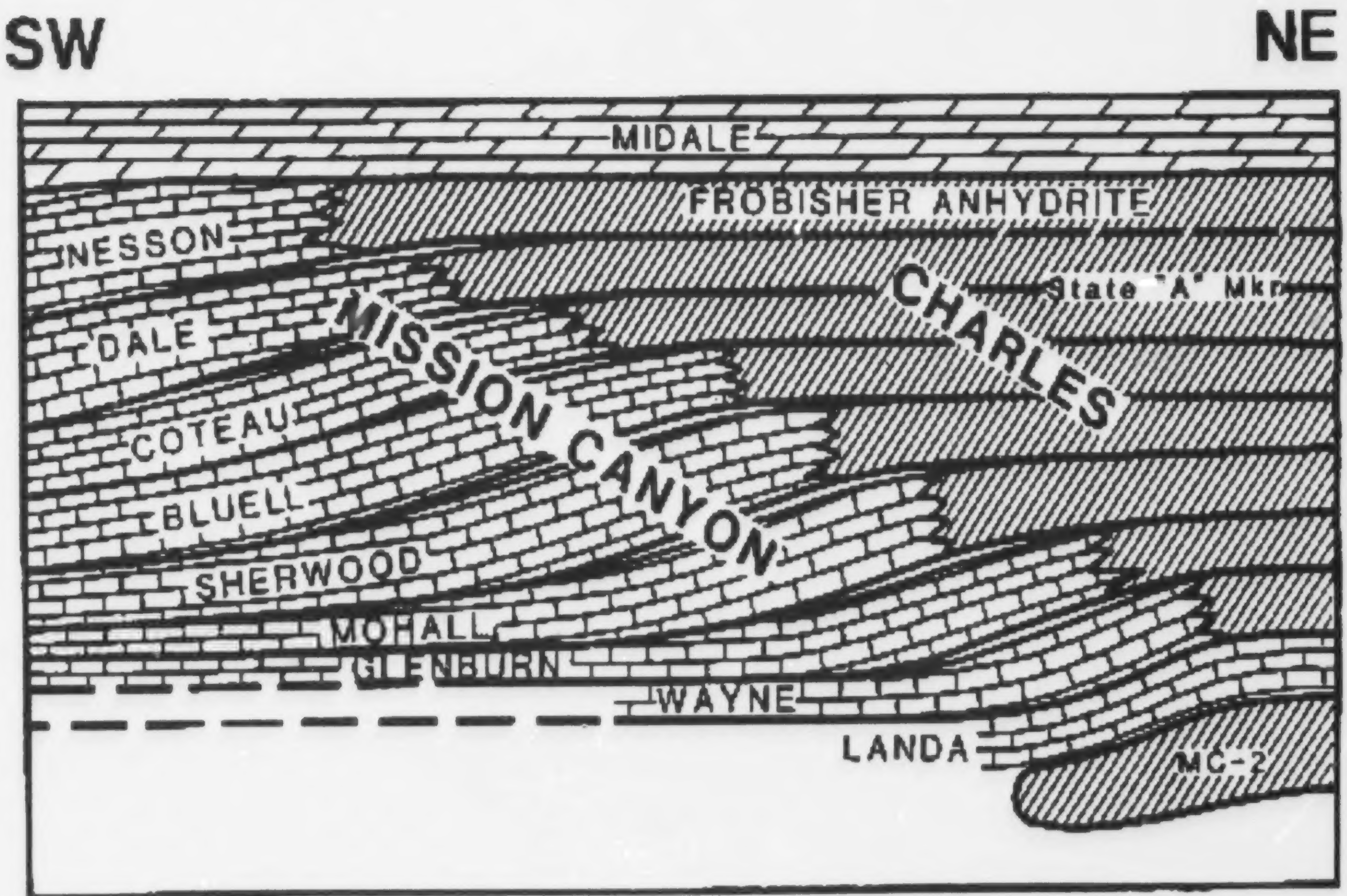
161 N 88 W
NORTH DAKOTA


TYPE LOG
KINSON-CLAYTON 1
162N-89W-18
UPPER BERENTSON MARKER
MIDALE POROSITY
NESSON - HORIZONTAL TARGET

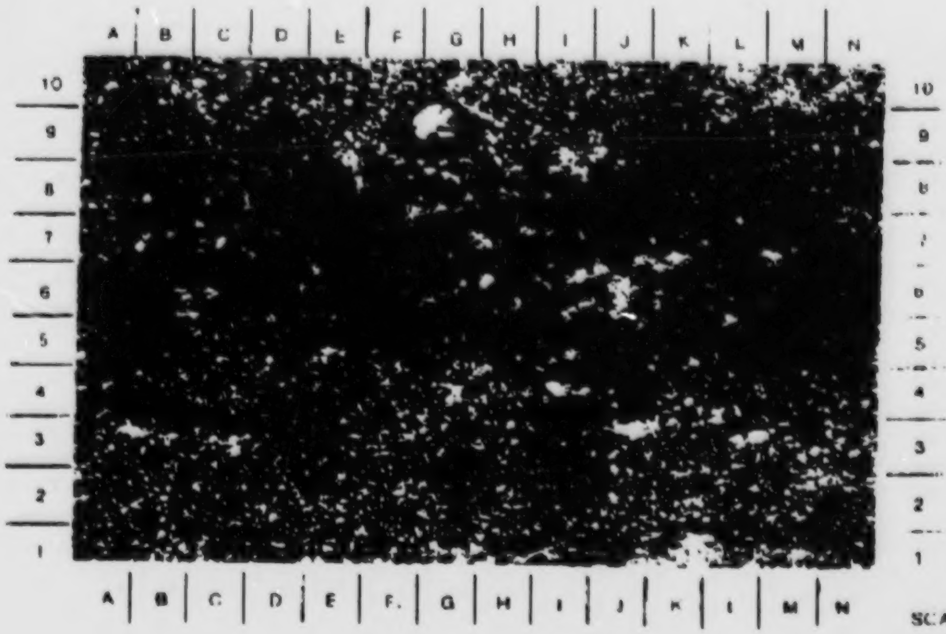


(from Voldseth, 1986)

MIDALE
2.4% σ
1.7 md K

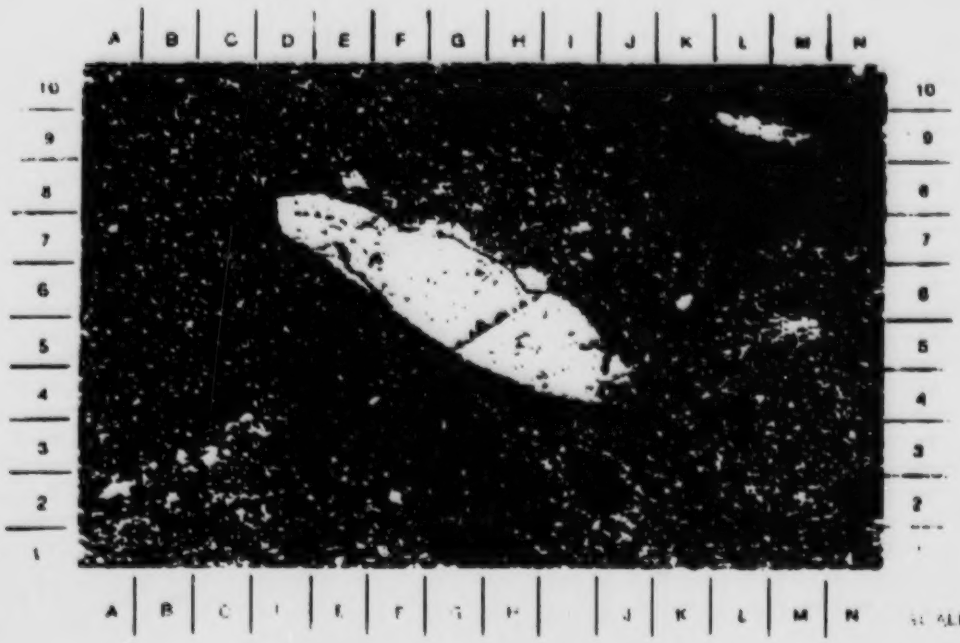
CORE DEPTH: 5772.5

A



SCALE
0.13m

B

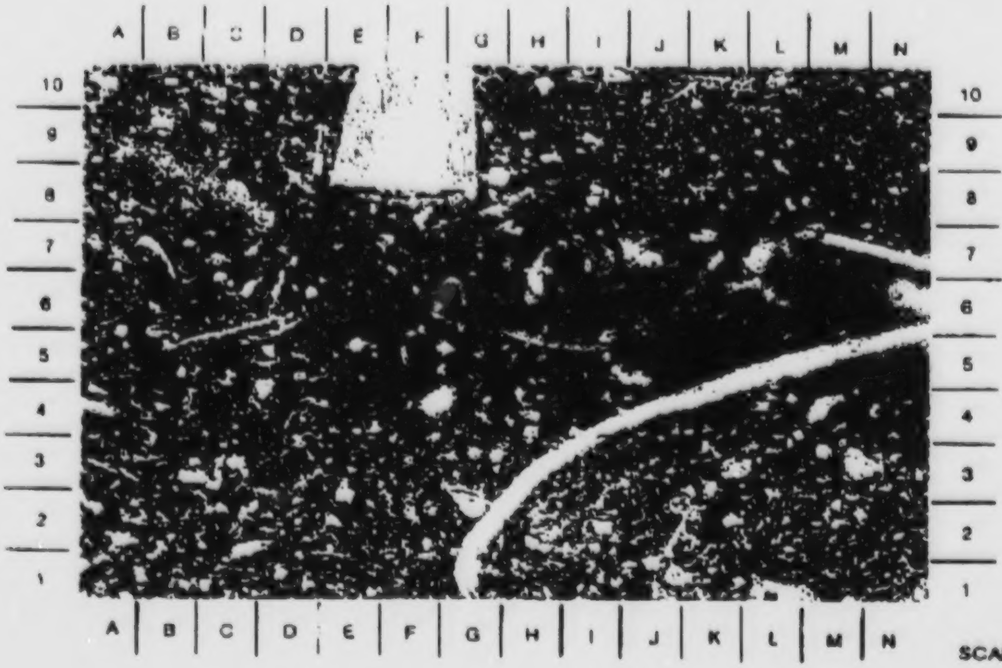


SCALE
0.13mm

CORE DEPTH: 5776.5

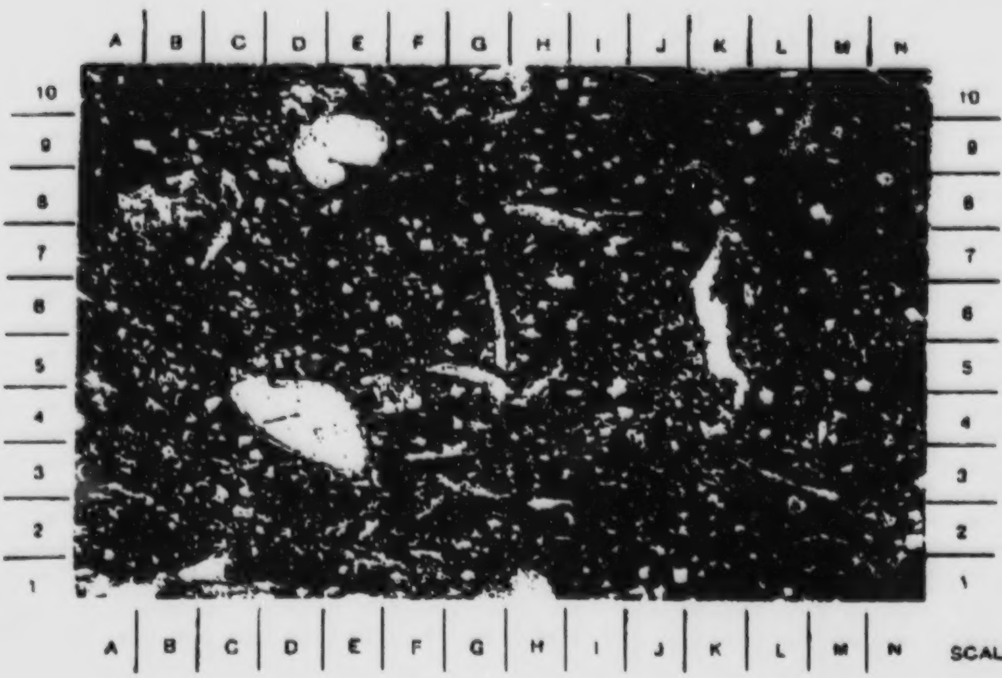
"TITE MIDALE"
8.5% σ
0.1 md K

C



SCALE: 0.32mm

D



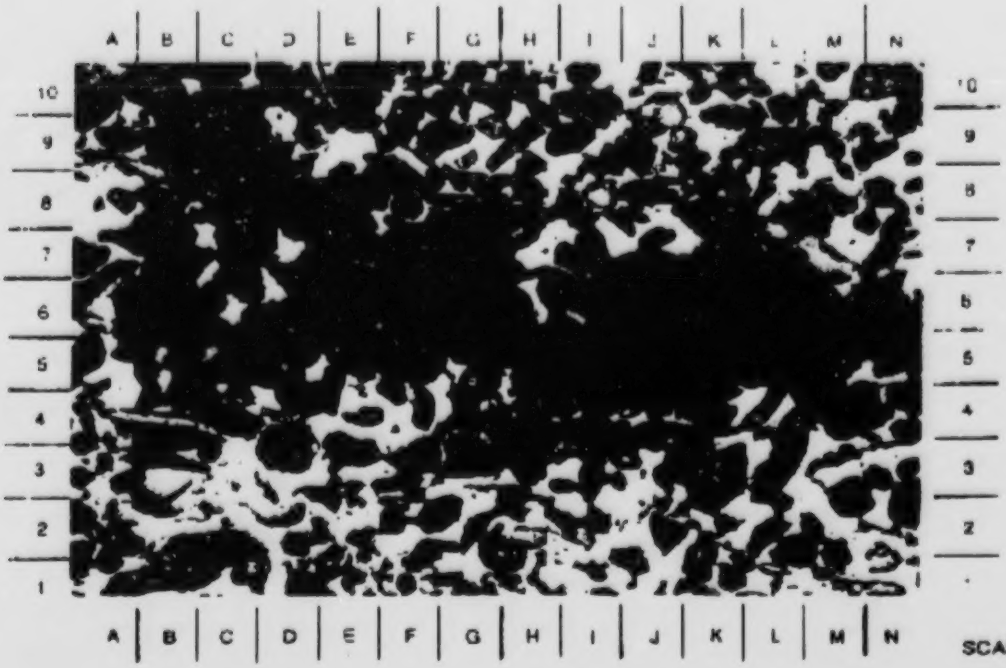
SCALE: 0.32mm

NESSON

CORE DEPTH: 5778.5 5.2 % ø

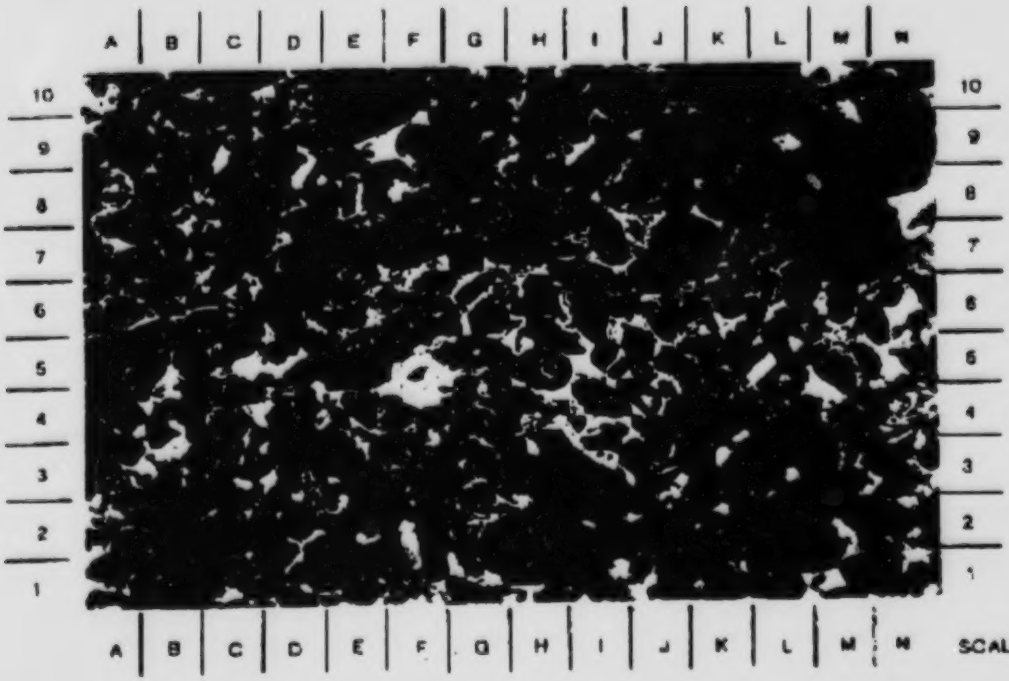
0.3 md K

C



SCALE: 0.5mm

D

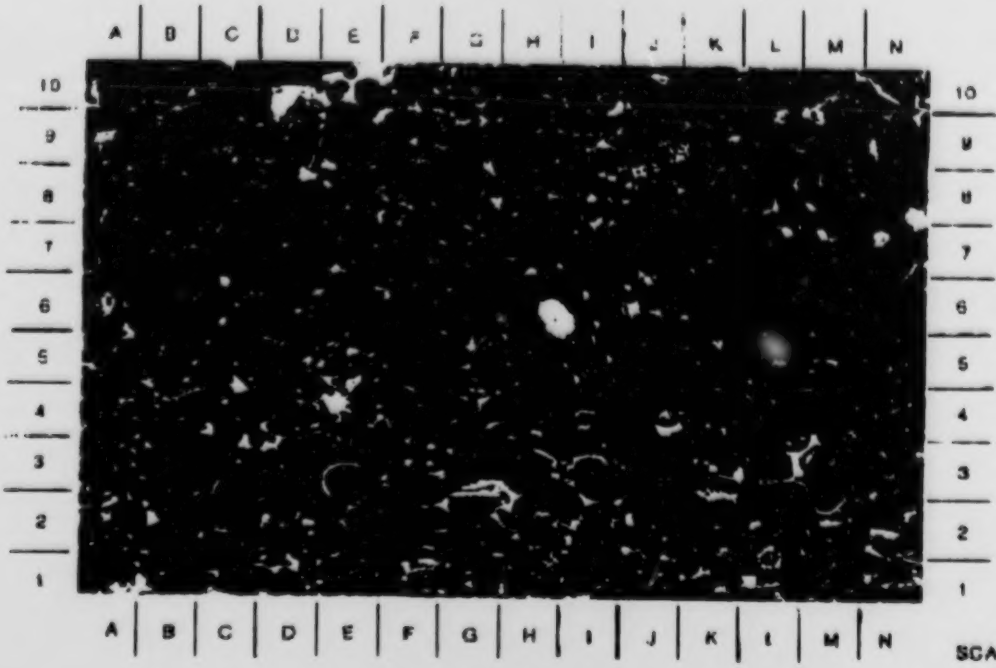


SCALE: 0.5mm

CORE DEPTH: 5780.5

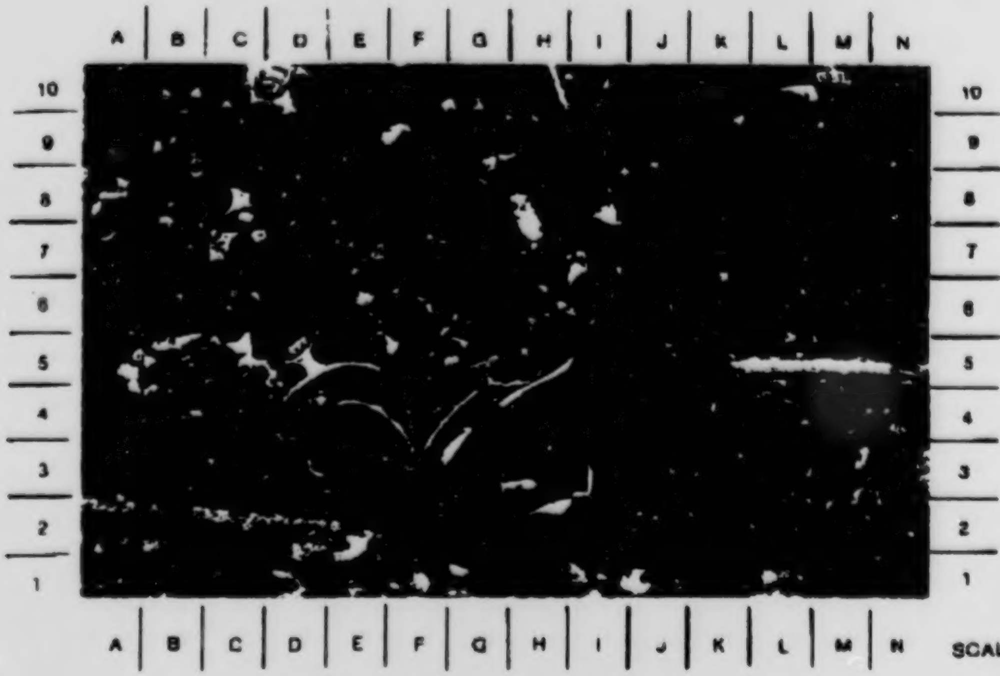
NESSON
14.4 % Ø
67 md K

C



SCALE: 0.5mm

D

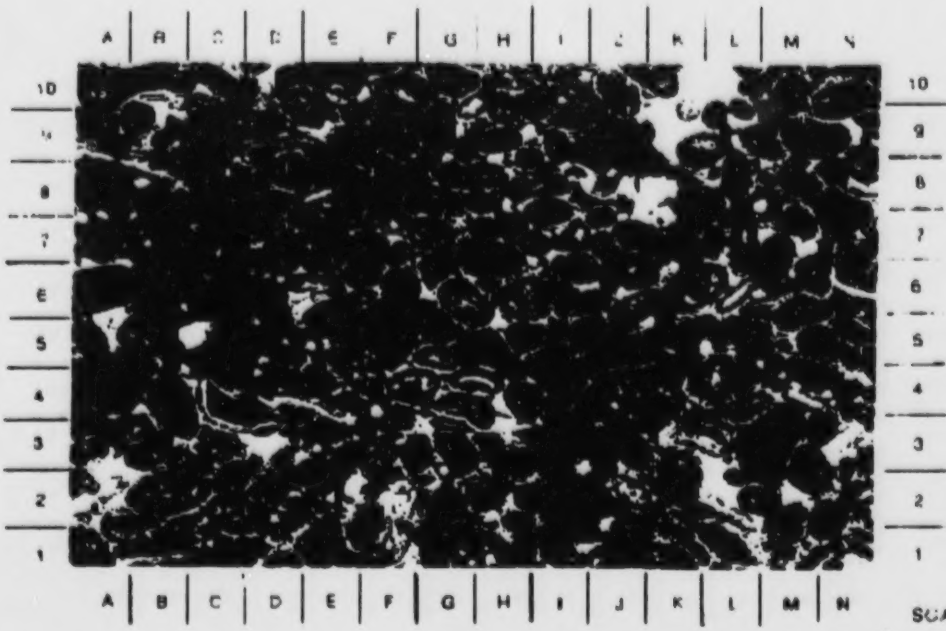


SCALE: 0.32mm

NESSON
14.7 % ø
17 md K

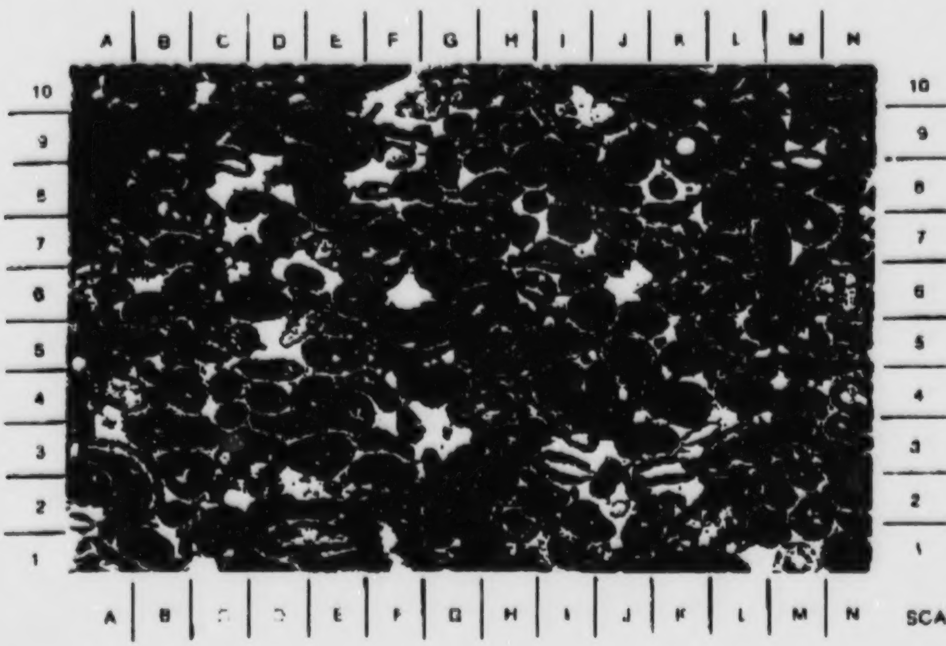
CORE DEPTH: 5783.2

A



SCALE: 0.32

B

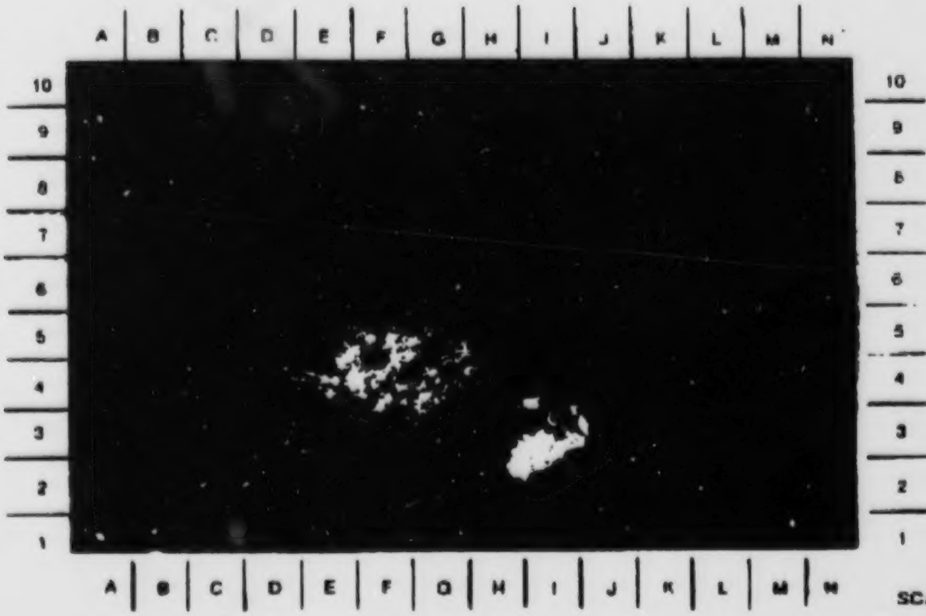


SCALE: 0.32mm

NESSON
11.3 % Ø
0.5 md K

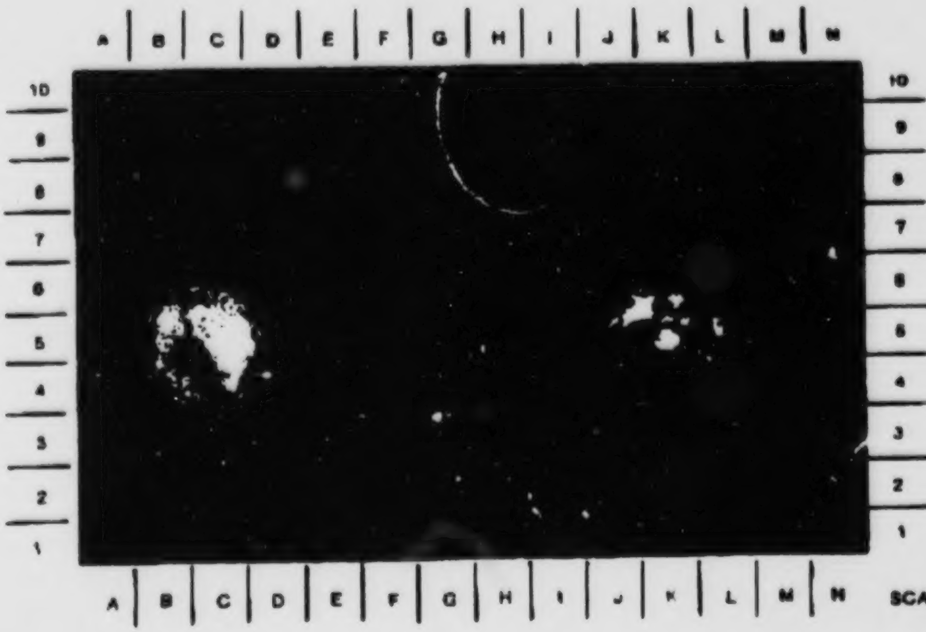
CORE DEPTH: 5785.5

A



SCALE
0.32mm

B

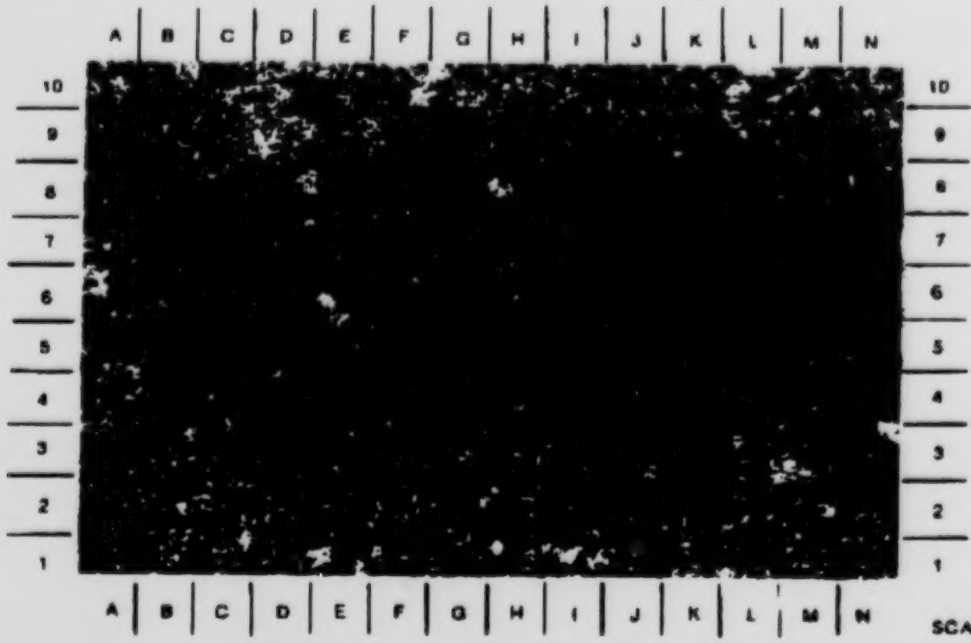


SCALE:
0.32mm

CORE DEPTH: 5787.8

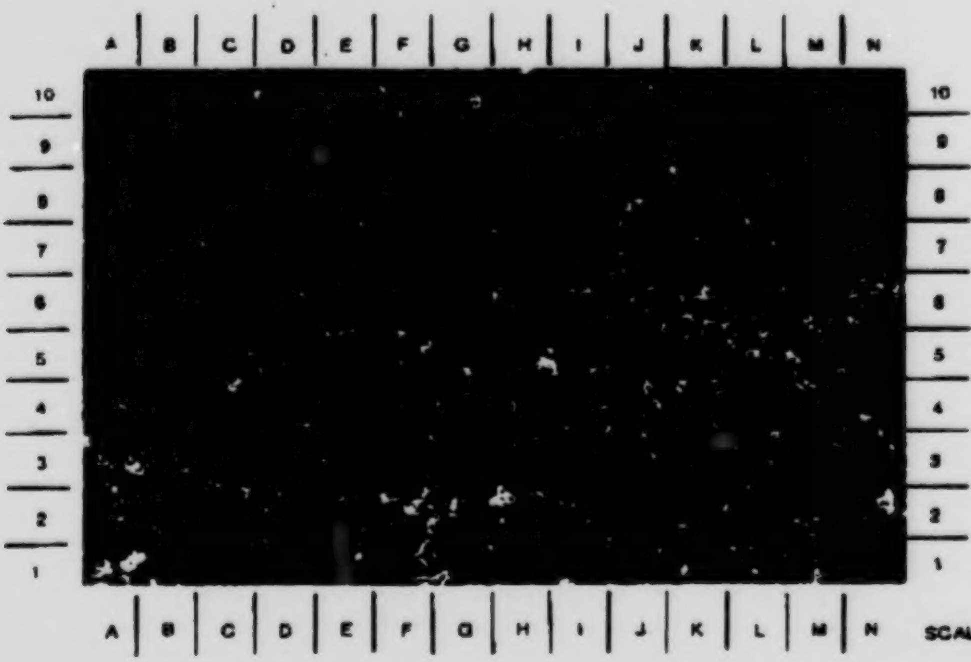
LESSON
10.3 % ø
2.7 md K

C



SCALE: 0.32mm

D



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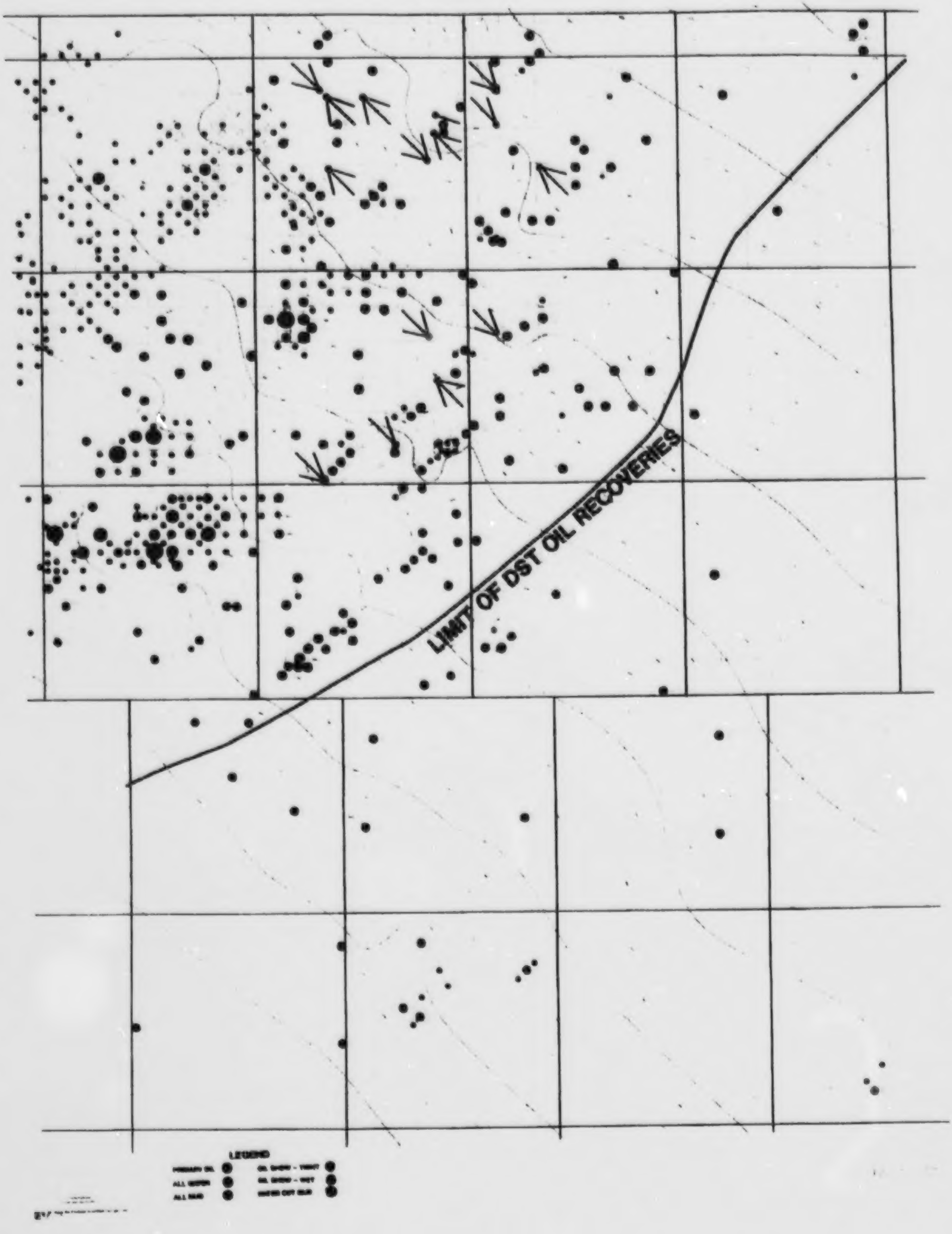
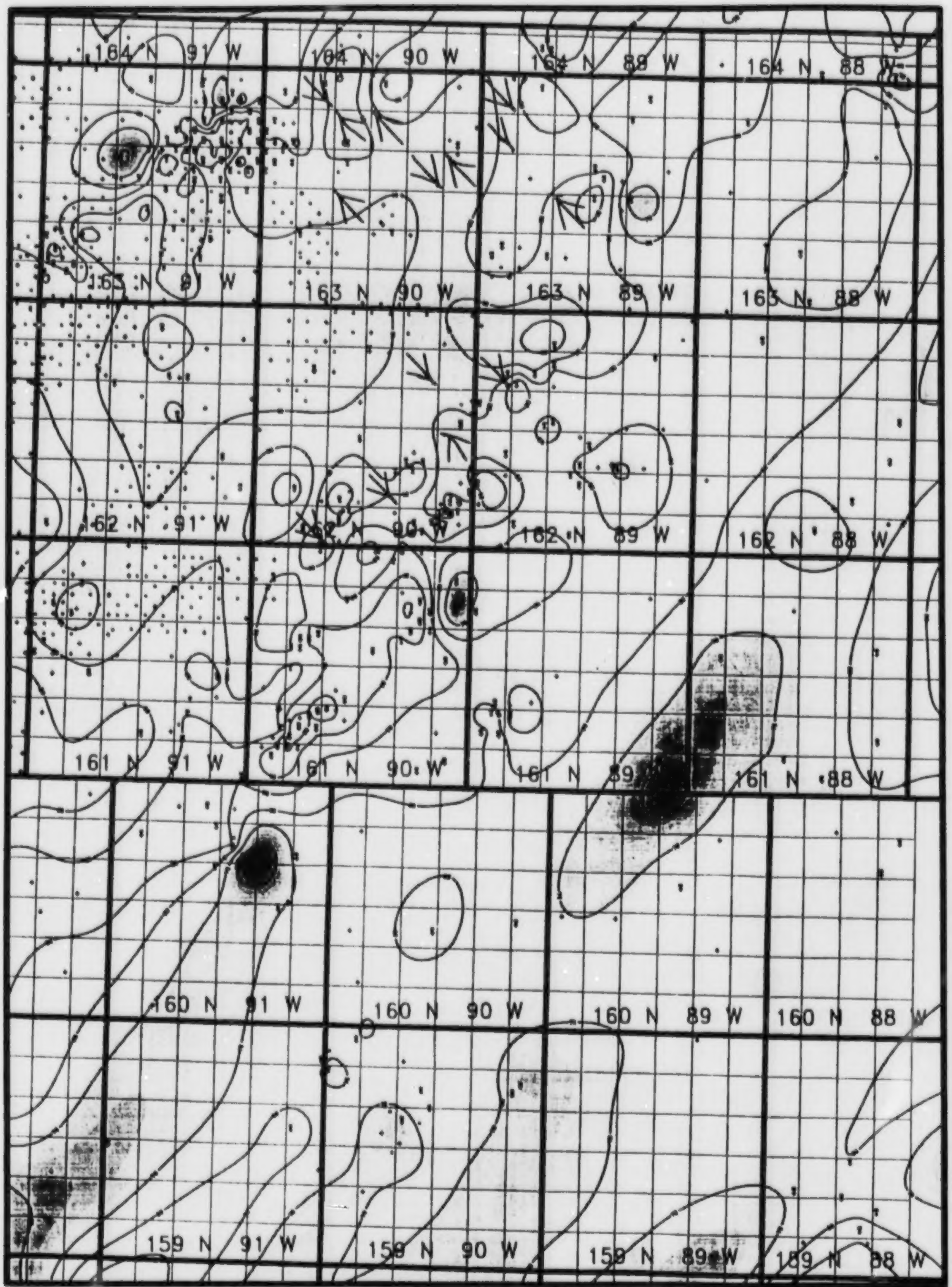
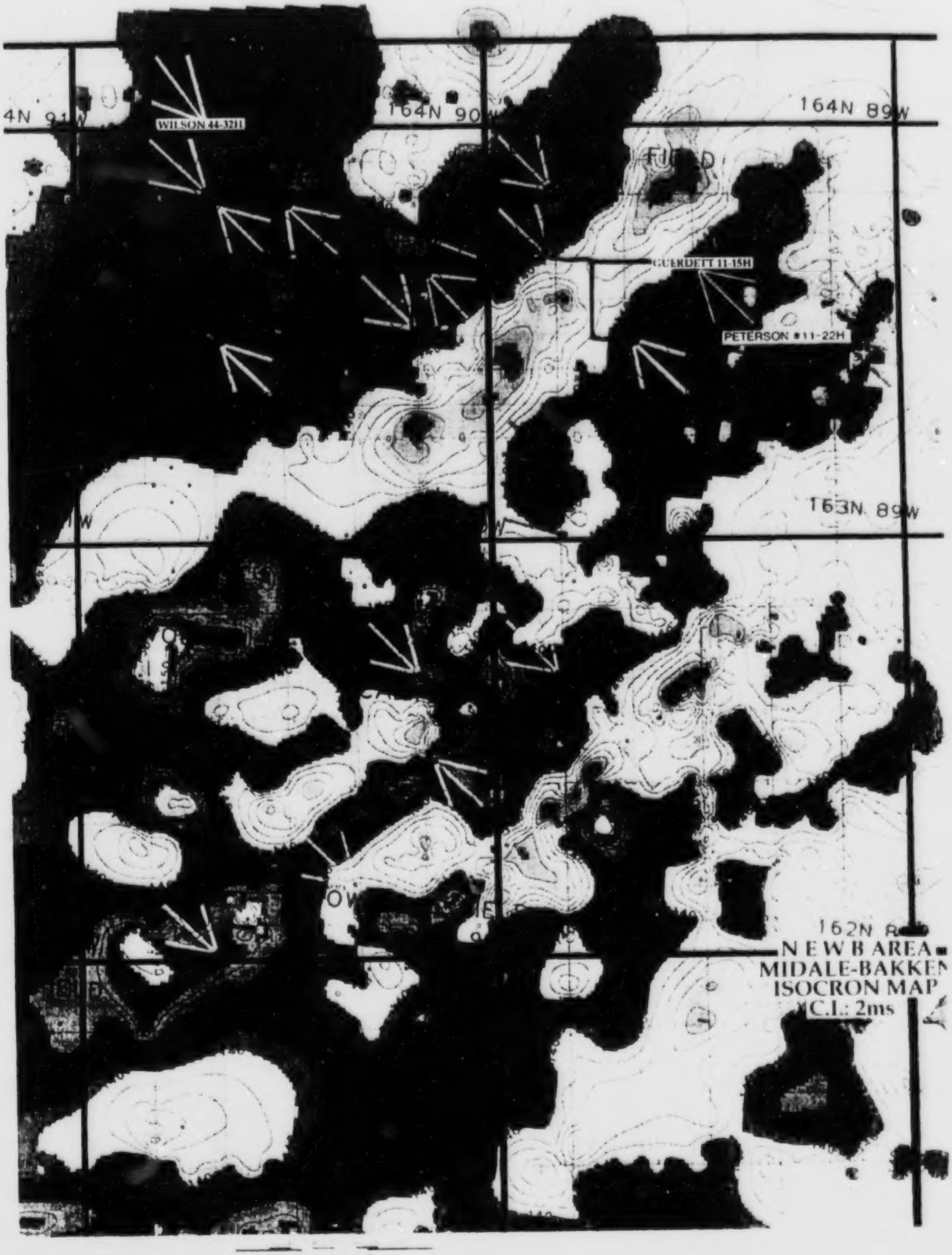

LIMIT OF DST OIL RECOVERIES
LEGEND

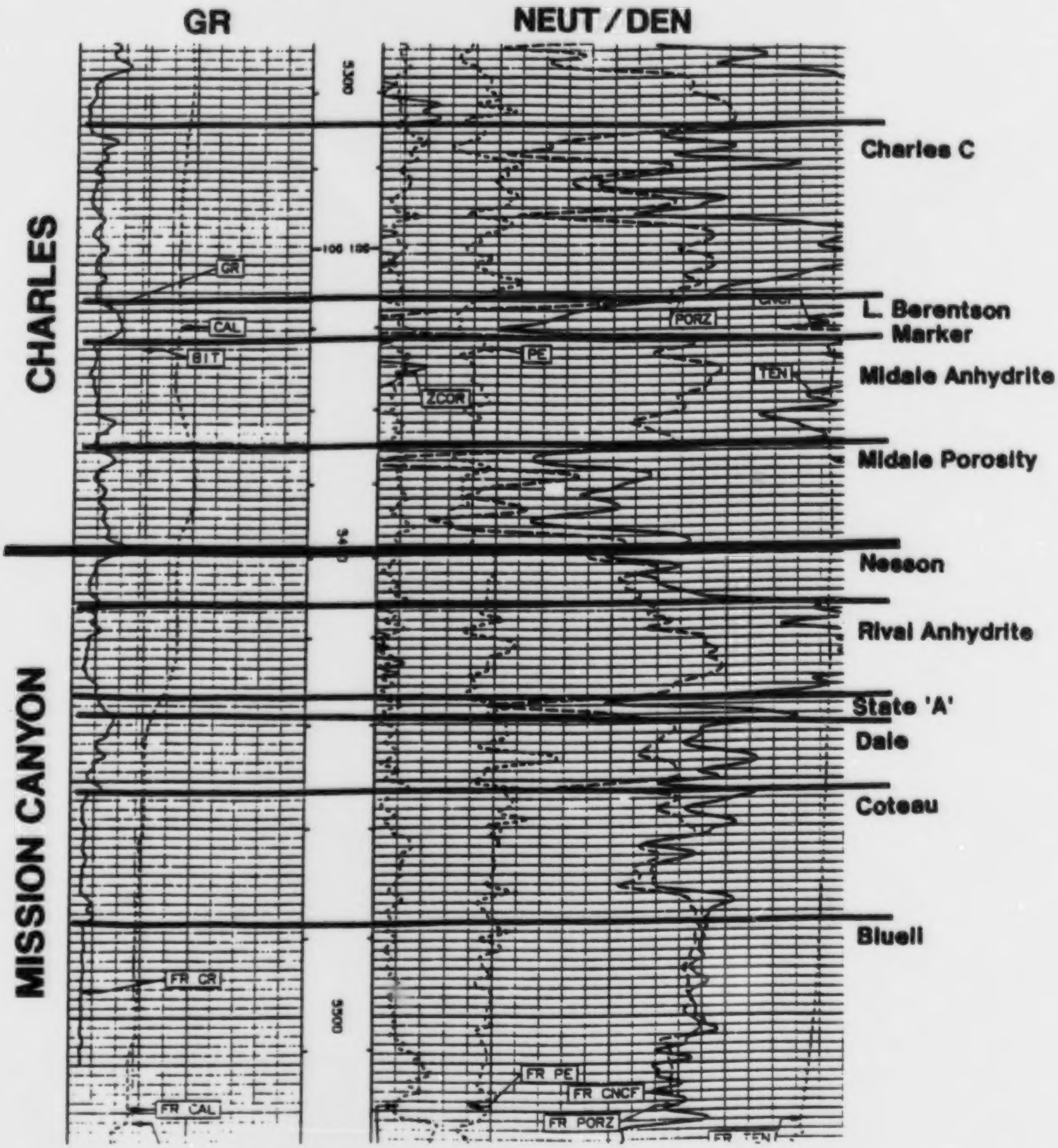


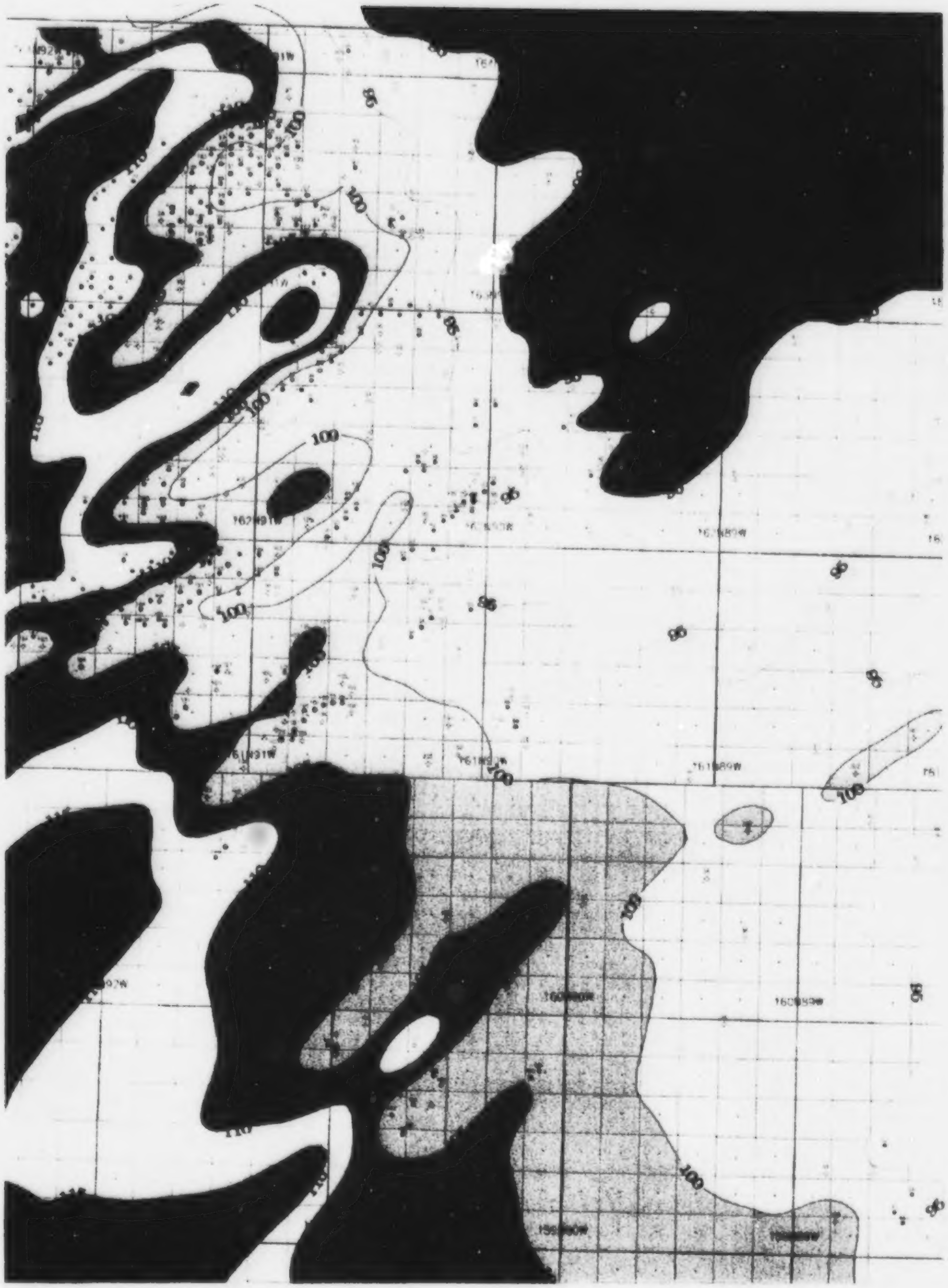
NESSON SW

BURLINGTON RESOURCES


WILSON 44-32H
164N 89W
GUERDETT 11-15H
PETERSON #11-22H
163N 89W
N E W B AREA
MIDALE-BAKKE
ISOCRON MAP
C.I.: 2ms

TYPE LOG
BURLINGTON RESOURCES OIL & GAS COMPANY
11-21H KNUDSON
NWNW Sec. 21, T 163N-R89W

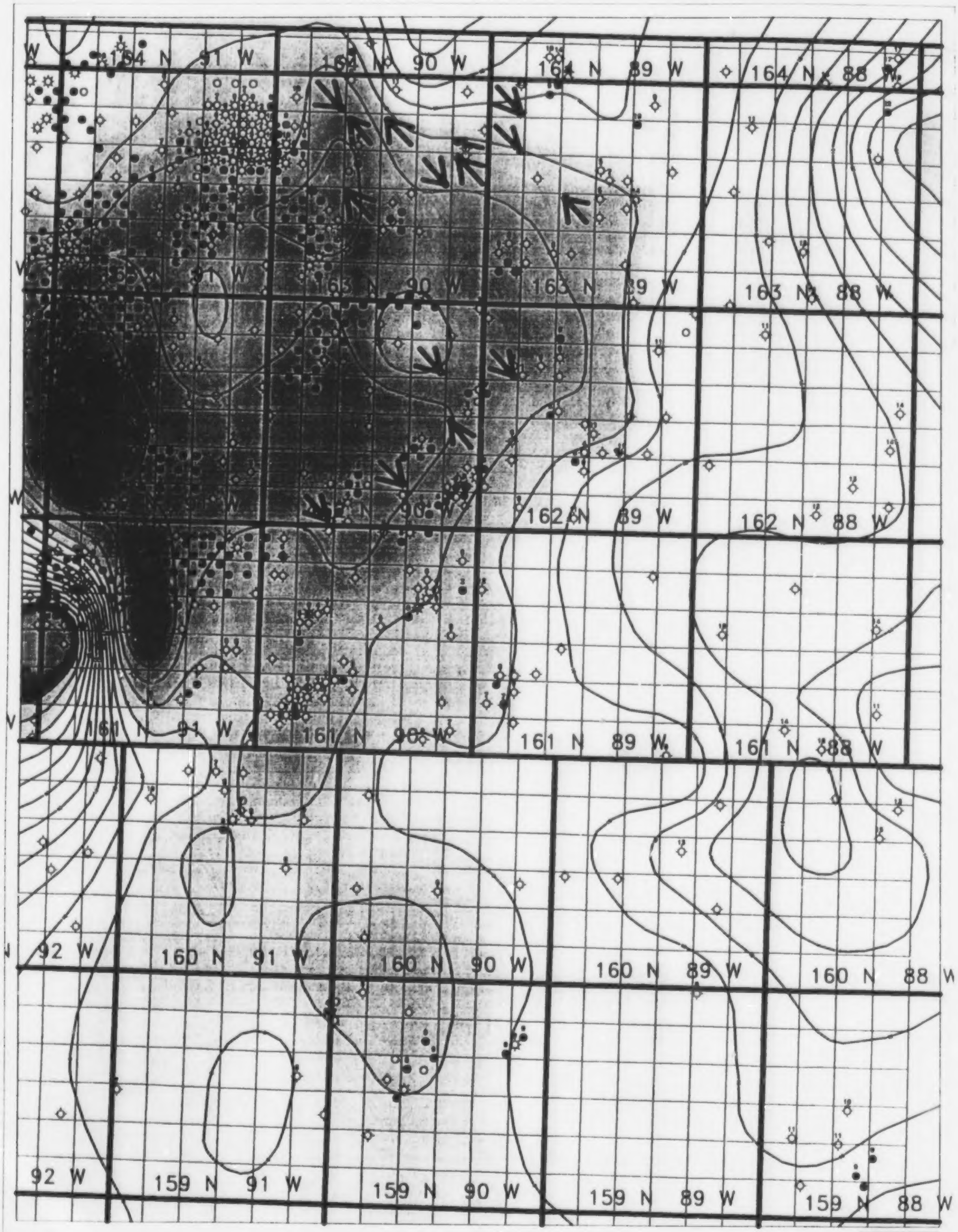




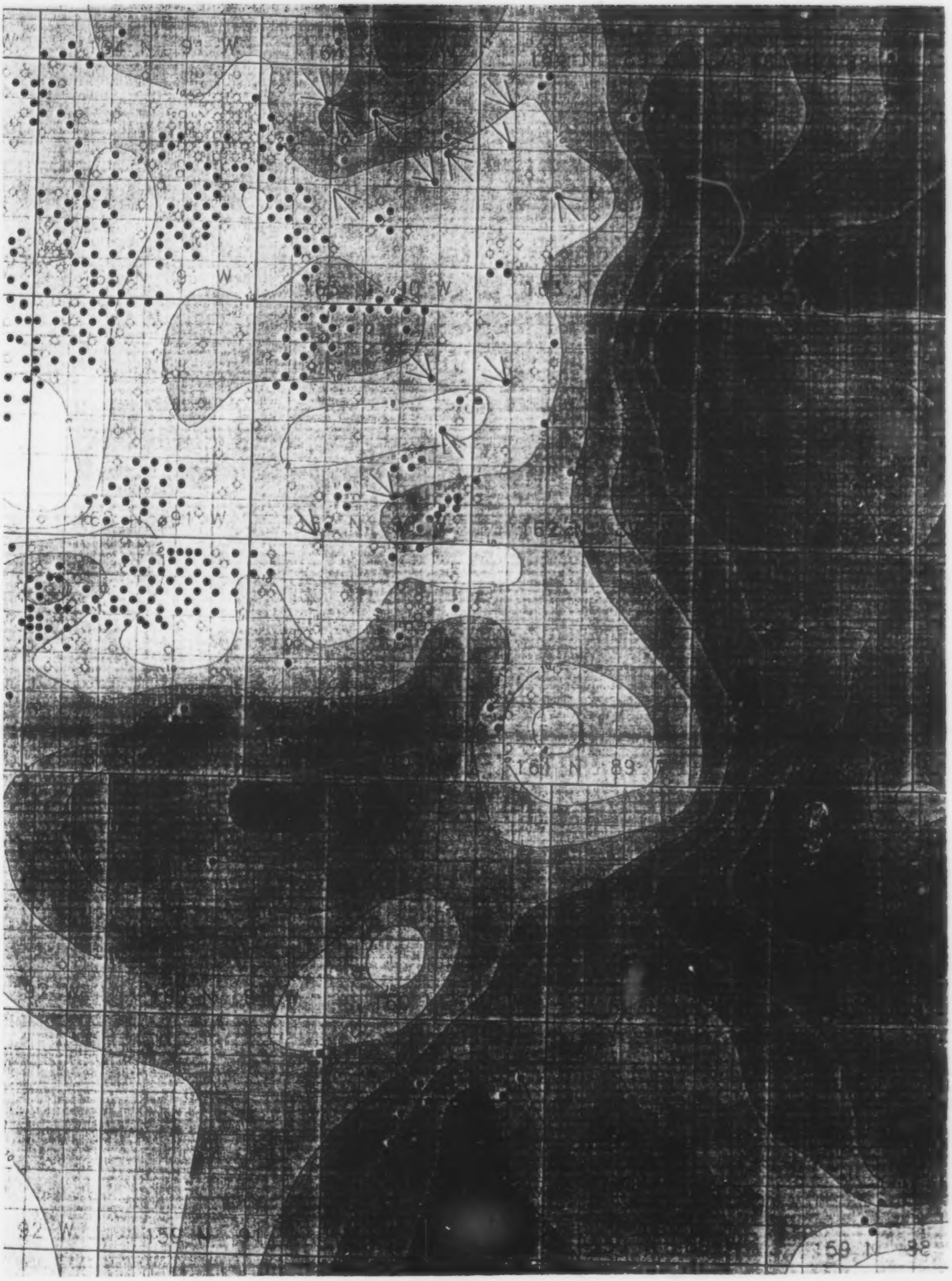
NORTHEAST WILLISTON PROSPECT
BURKE COUNTY, N.D.

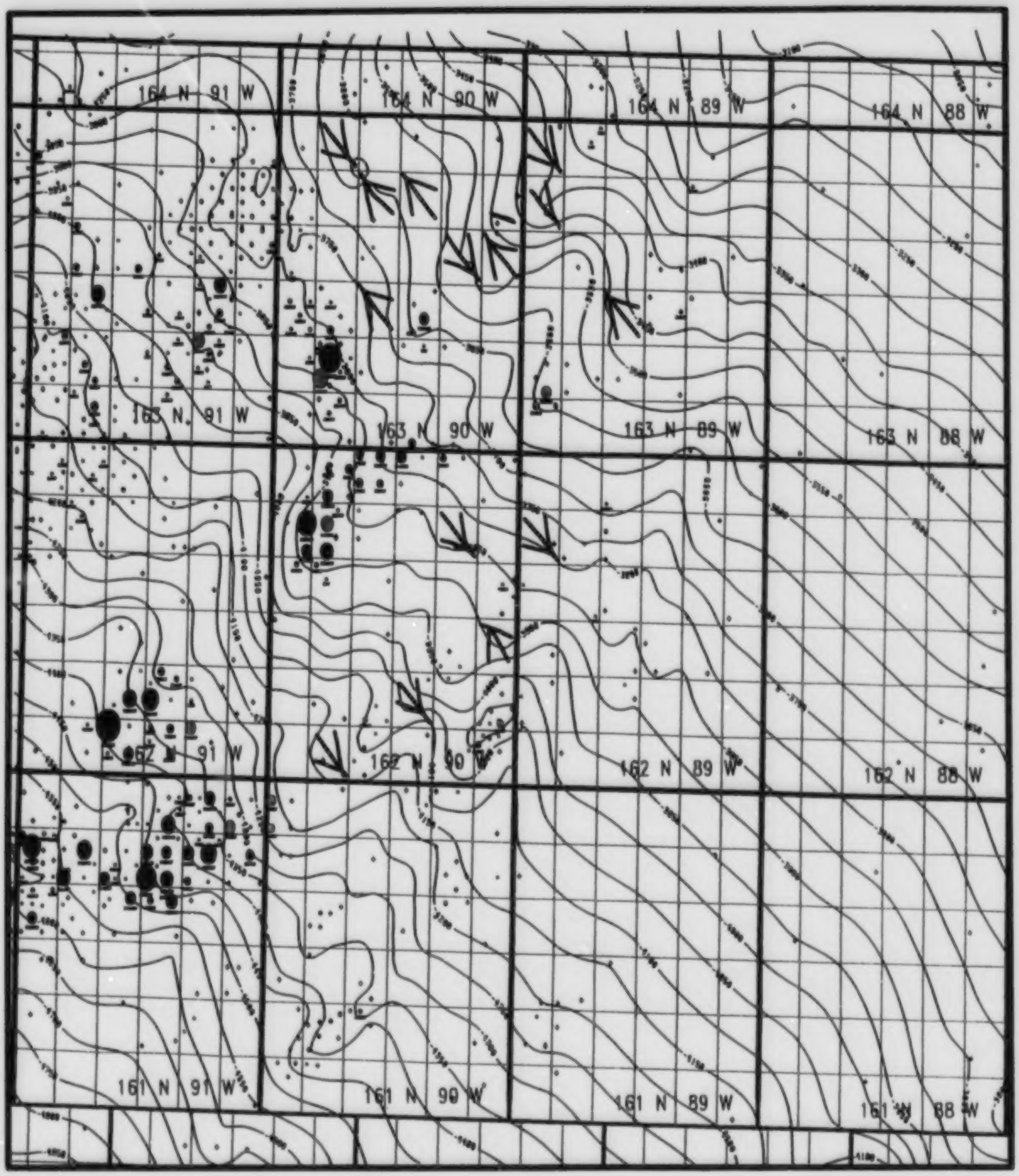
Burlington Resources Oil and Gas Co

BURKE COUNTY2
GLOBAL



TOTAL NESSON POROSITY THICKNESS

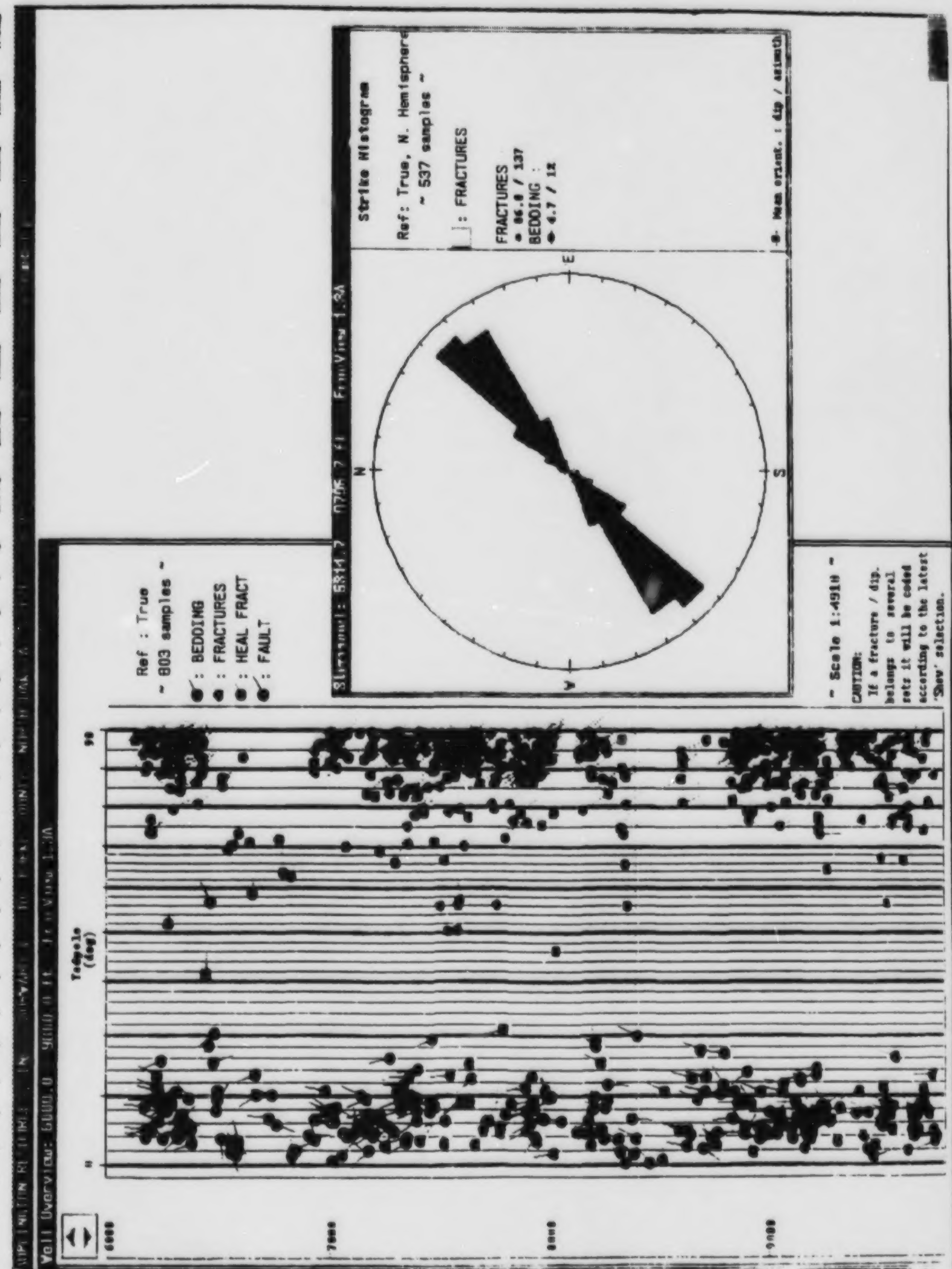




NESSON PRODUCTION
MIDALE PRODUCTION
MIDALE/NESSON PRODUCTION

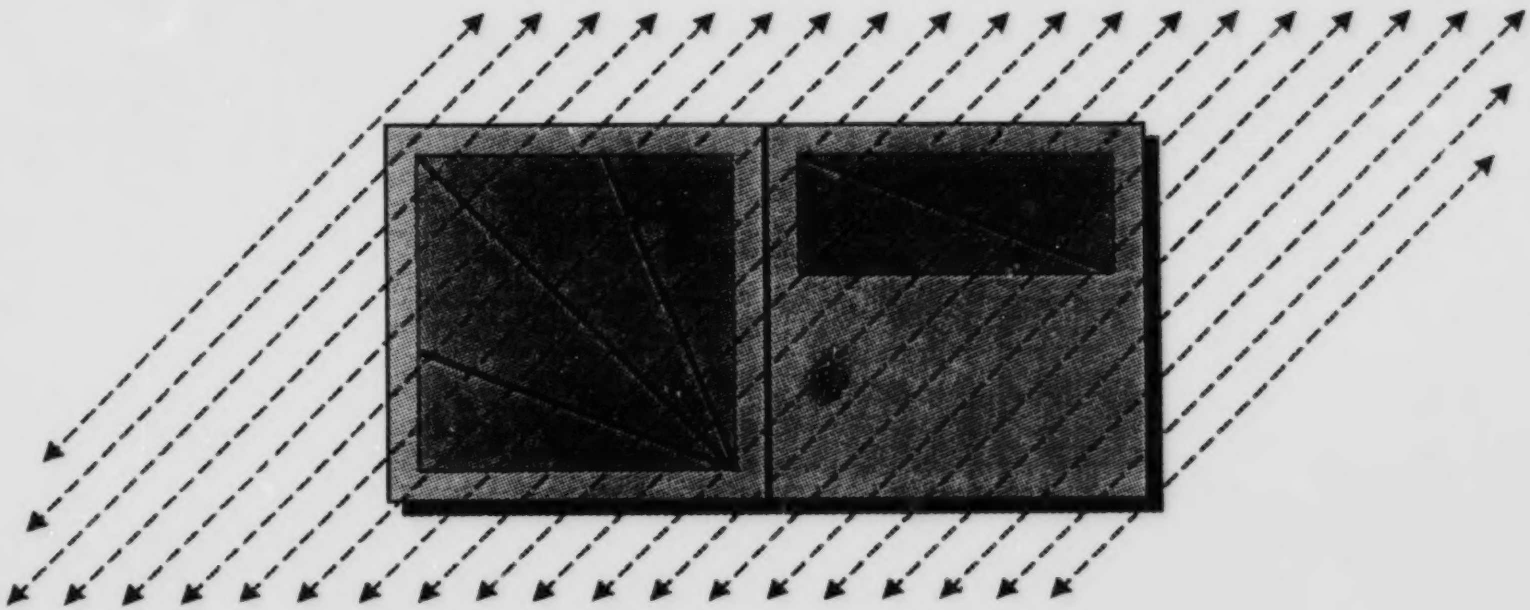
BURLINGTON RESOURCES
Mid-Continent Division

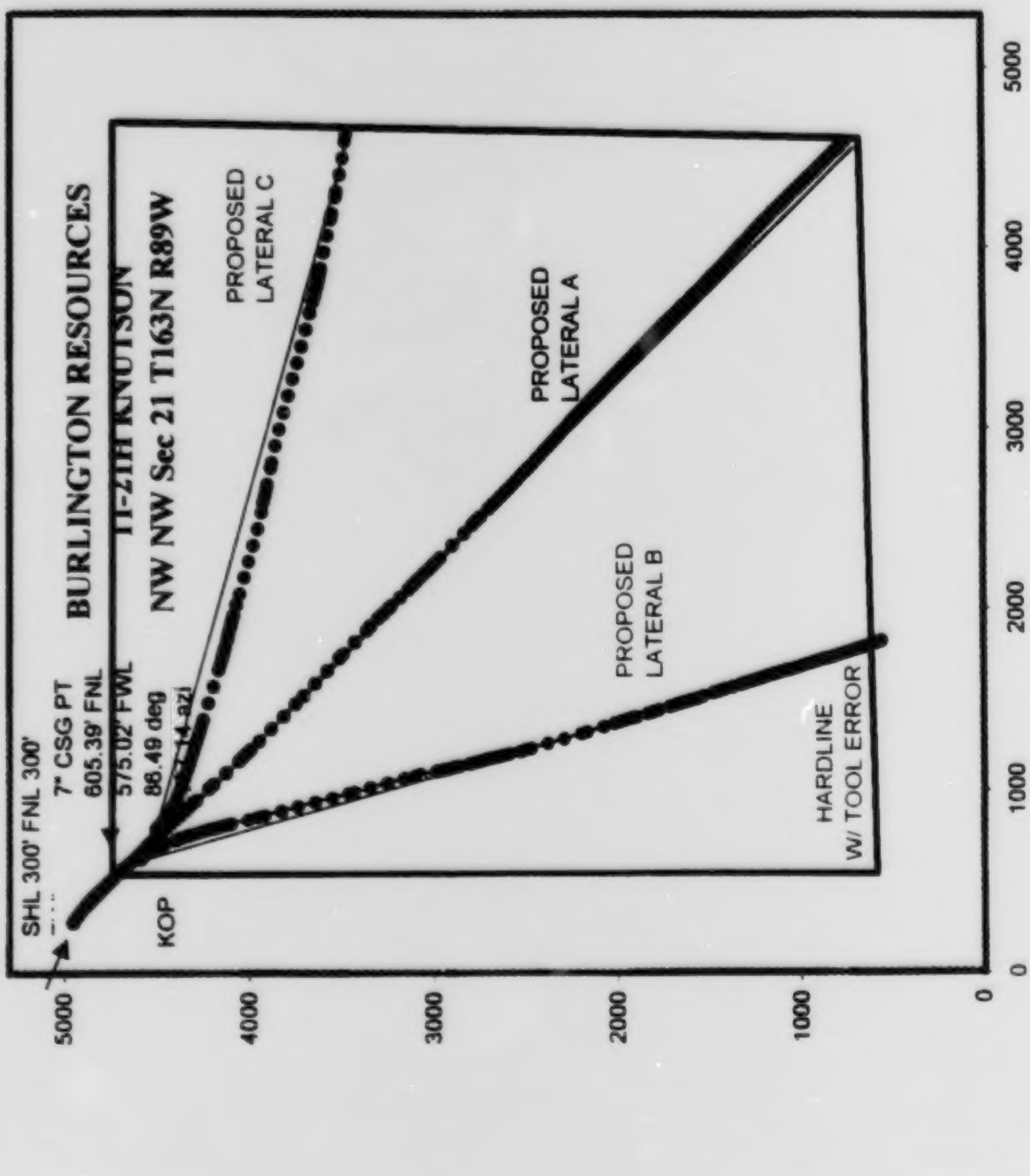
N. BURKE COUNTY
STRUCTURE NESSON SUBSEA
CI = 50'

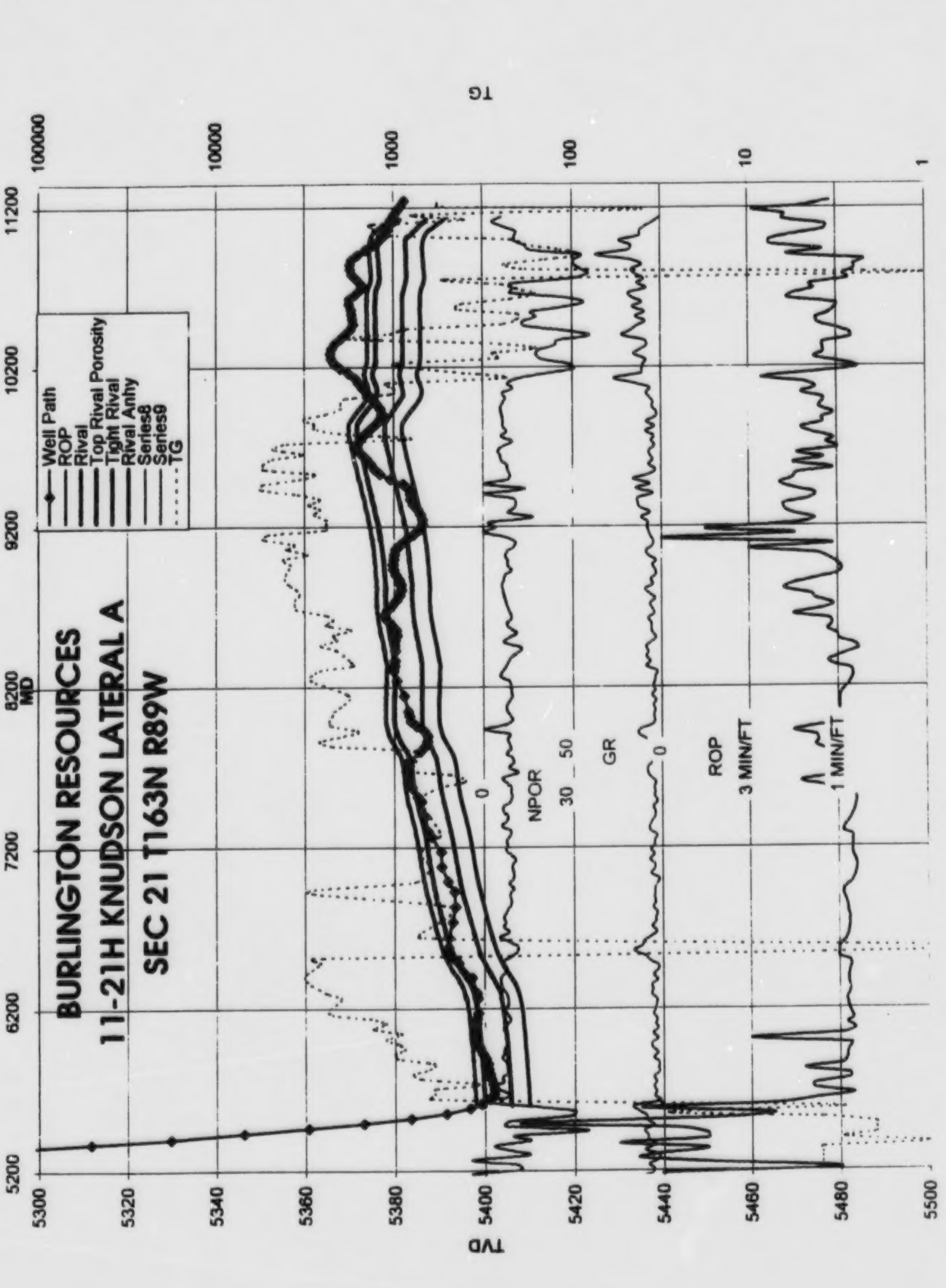


Strike Histogram
Ref: True, N. Hemisphere
~ 537 samples ~
: FRACTURES
FRACTURES
BEDDING :
Mean orient. : dip / azimuth
N
E
S
W
Ref : True
~ 803 samples ~
: BEDDING
: FRACTURES
: HEAL FRACT
: FAULT
CAUTION:
If a fracture / dip. belongs to several sets it will be coded according to the latest 'Show' selection.
Tadpole (deg)
0
90
6000
7000
8000
9000

Regional Fracture System & Wellbore Azimuth Relation

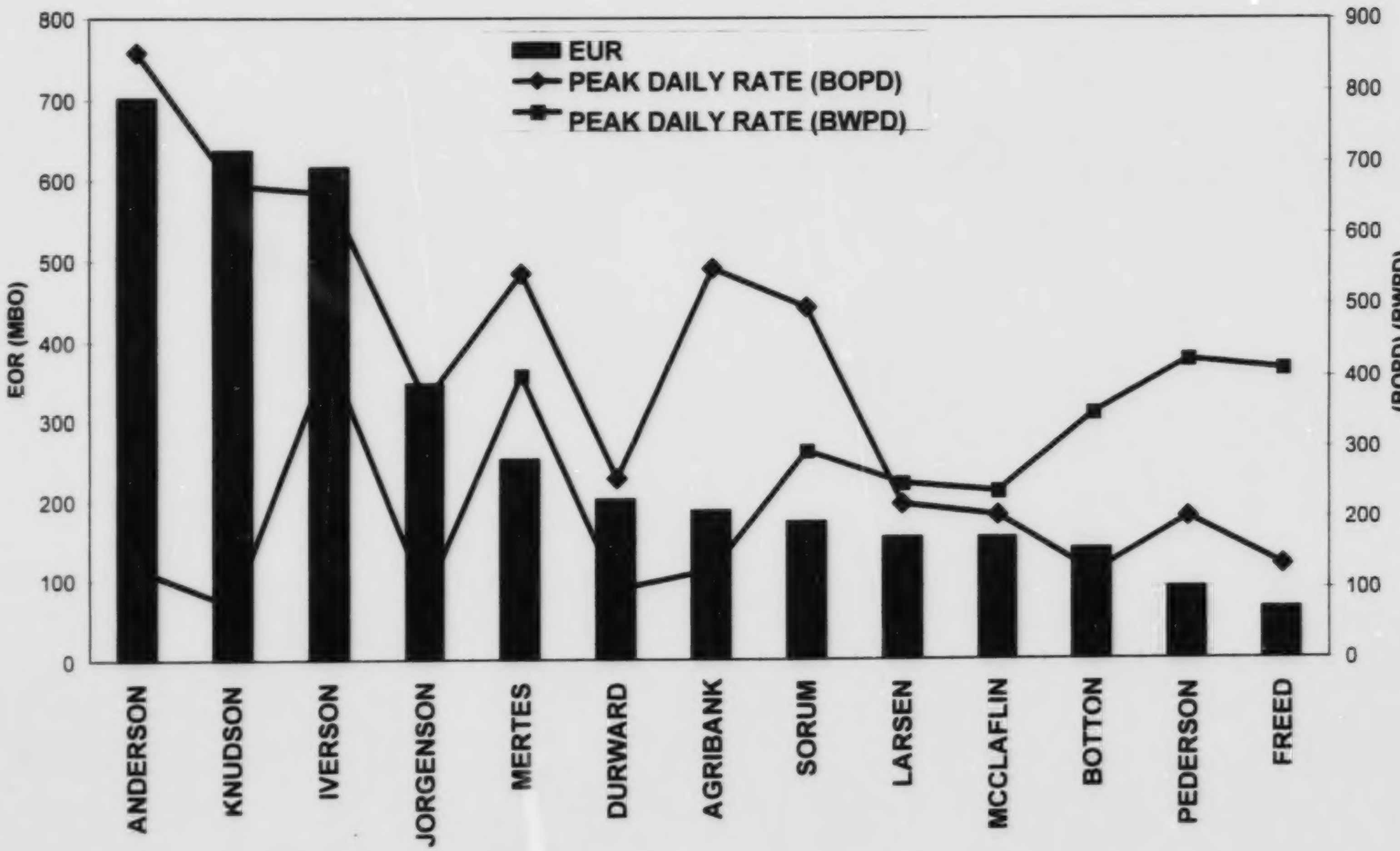



BURLINGTON RESOURCES
11-21H KNUTSON
NW NW Sec 21 T163N R89W
SHL 300' FNL 300'
7" CSG PT
605.39' FNL
575.02' FWL
86.49 deg
KOP
PROPOSED LATERAL C
PROPOSED LATERAL A
PROPOSED LATERAL B
HARDLINE W/ TOOL ERROR
0
1000
2000
3000
4000
5000

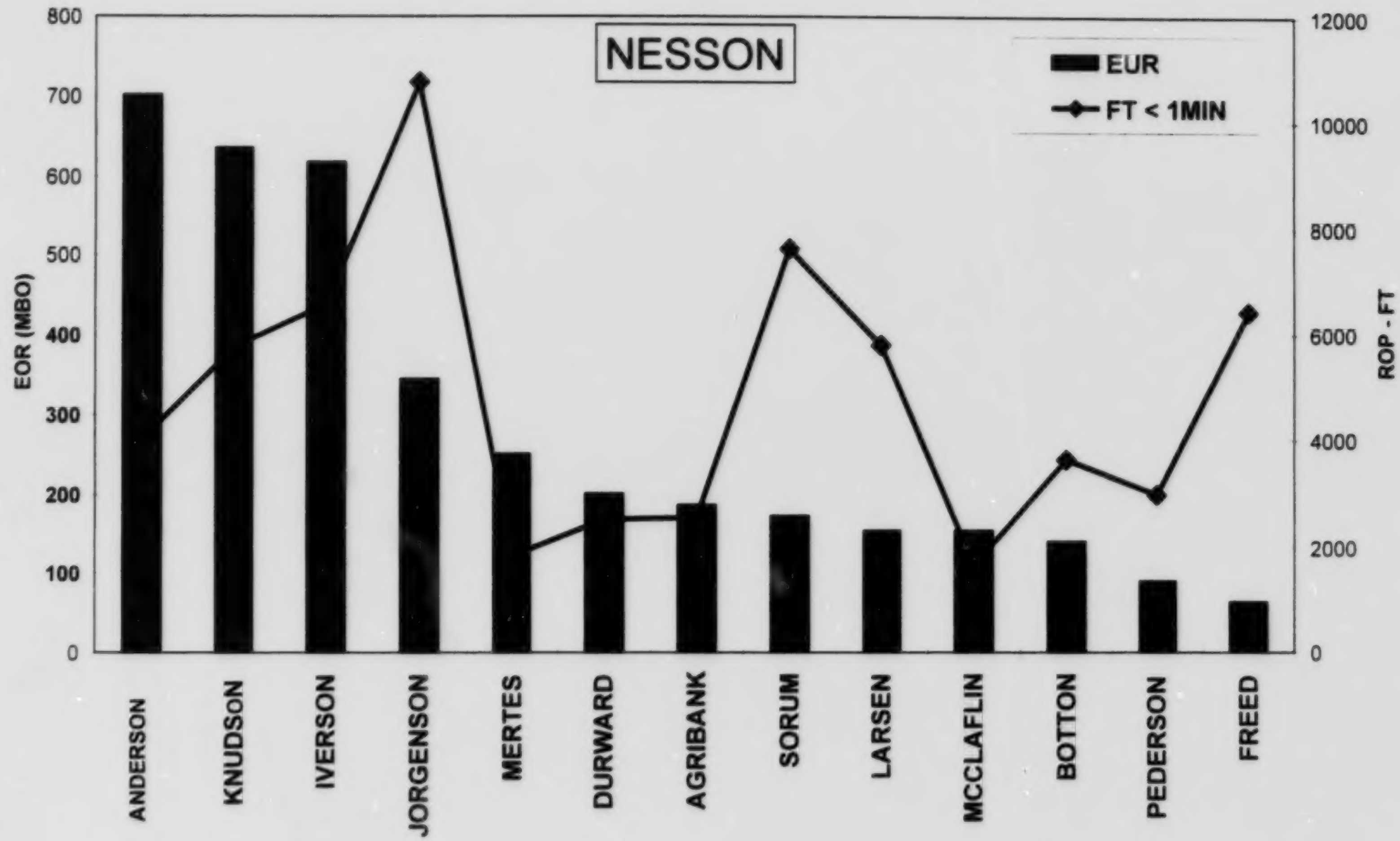


BURLINGTON RESOURCES
11-21H KNUDSON LATERAL A
SEC 21 T163N R89W
Well Path
ROP
Rival
Top Rival Porosity
Tight Rival
Rival Anhy
Series8
Series9
TG
TVD
MD
5300
5320
5340
5360
5380
5400
5420
5440
5460
5480
5500
5200
6200
7200
8200
9200
10200
11200
100000
10000
1000
100
10
1
0
NPOR
30
50
GR
0
ROP
3 MIN/FT
1 MIN/FT

EUR vs. PEAK DAILY RATE

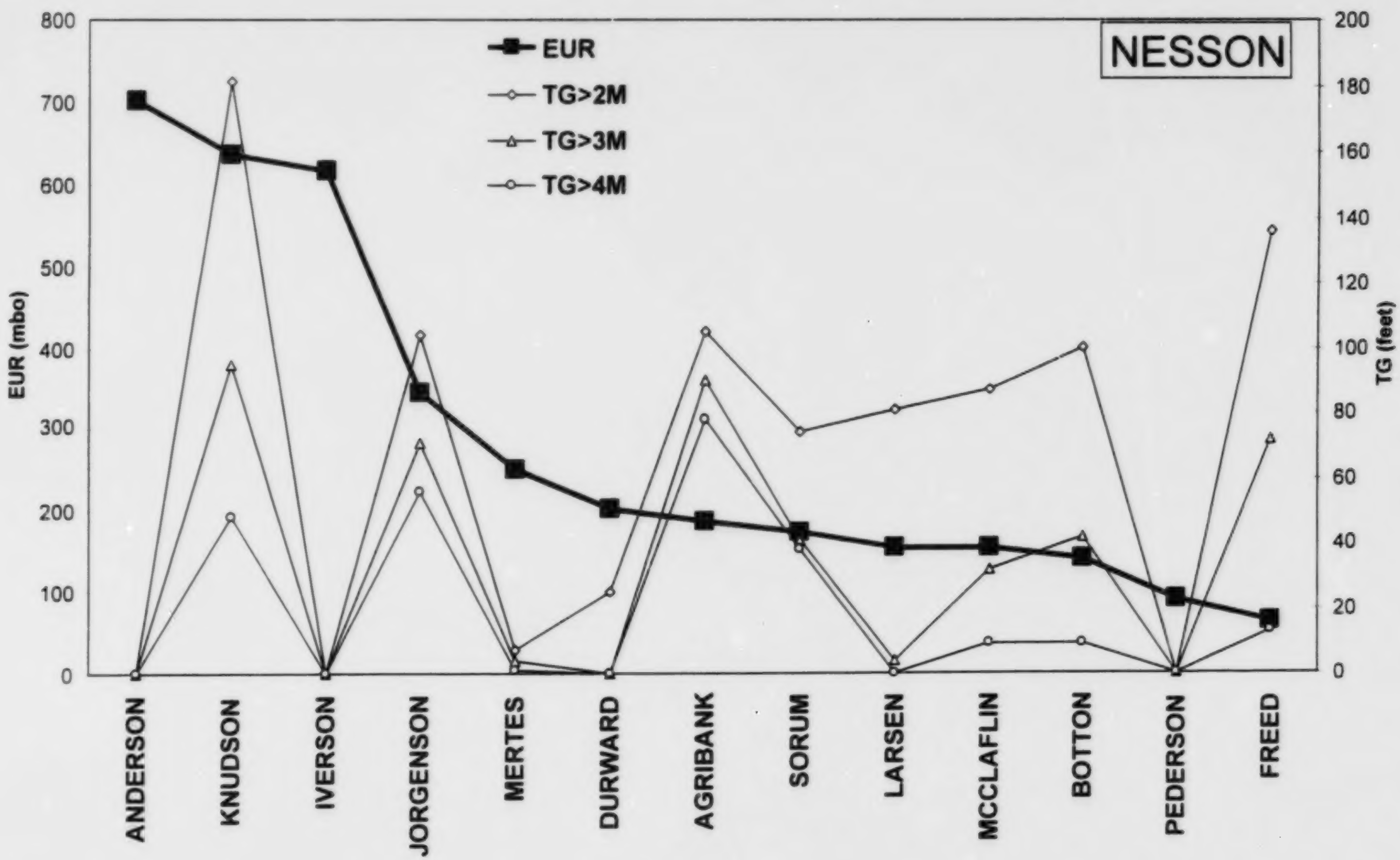


ROP vs. EUR

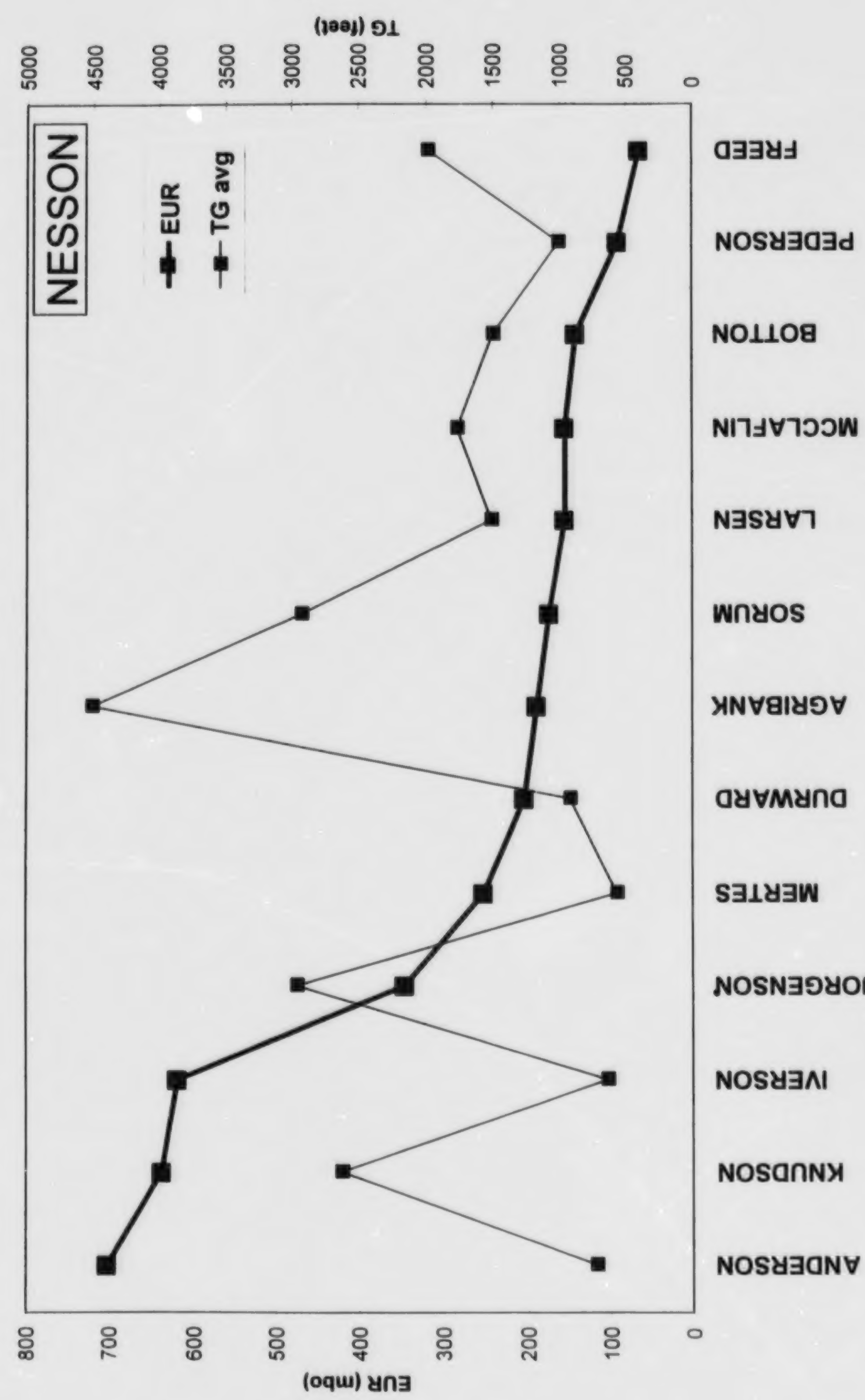


NESSON
EUR
FT < 1MIN
EOR (MBO)
ROP - FT
800
700
600
500
400
300
200
100
0
12000
10000
8000
6000
4000
2000
0
ANDERSON
KNUDSON
IVERSON
JORGENSON
MERTES
DURWARD
AGRIBANK
SORUM
LARSEN
MCCLAFLIN
BOTTON
PEDERSON
FREED

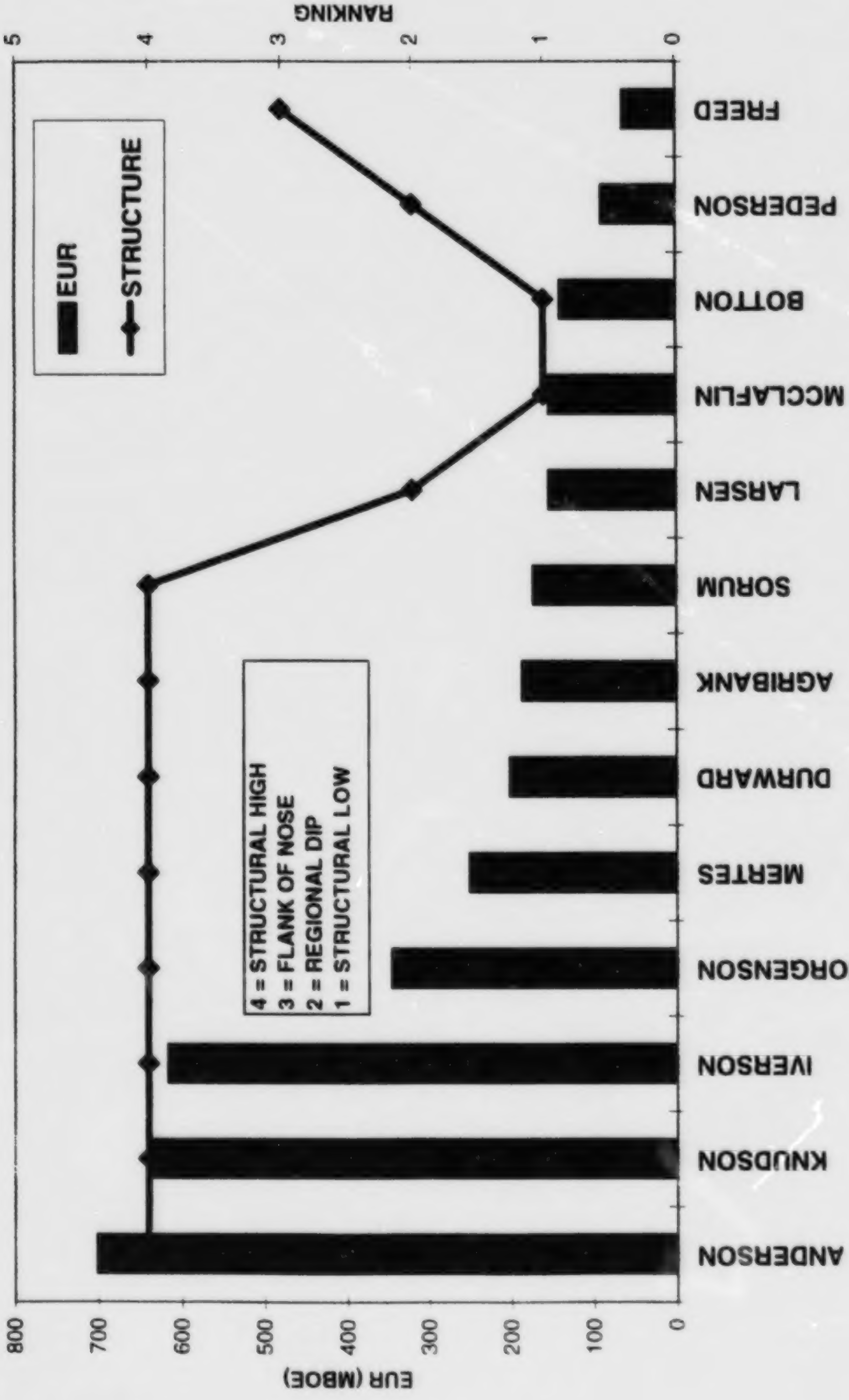
EUR vs TG (survey pts)

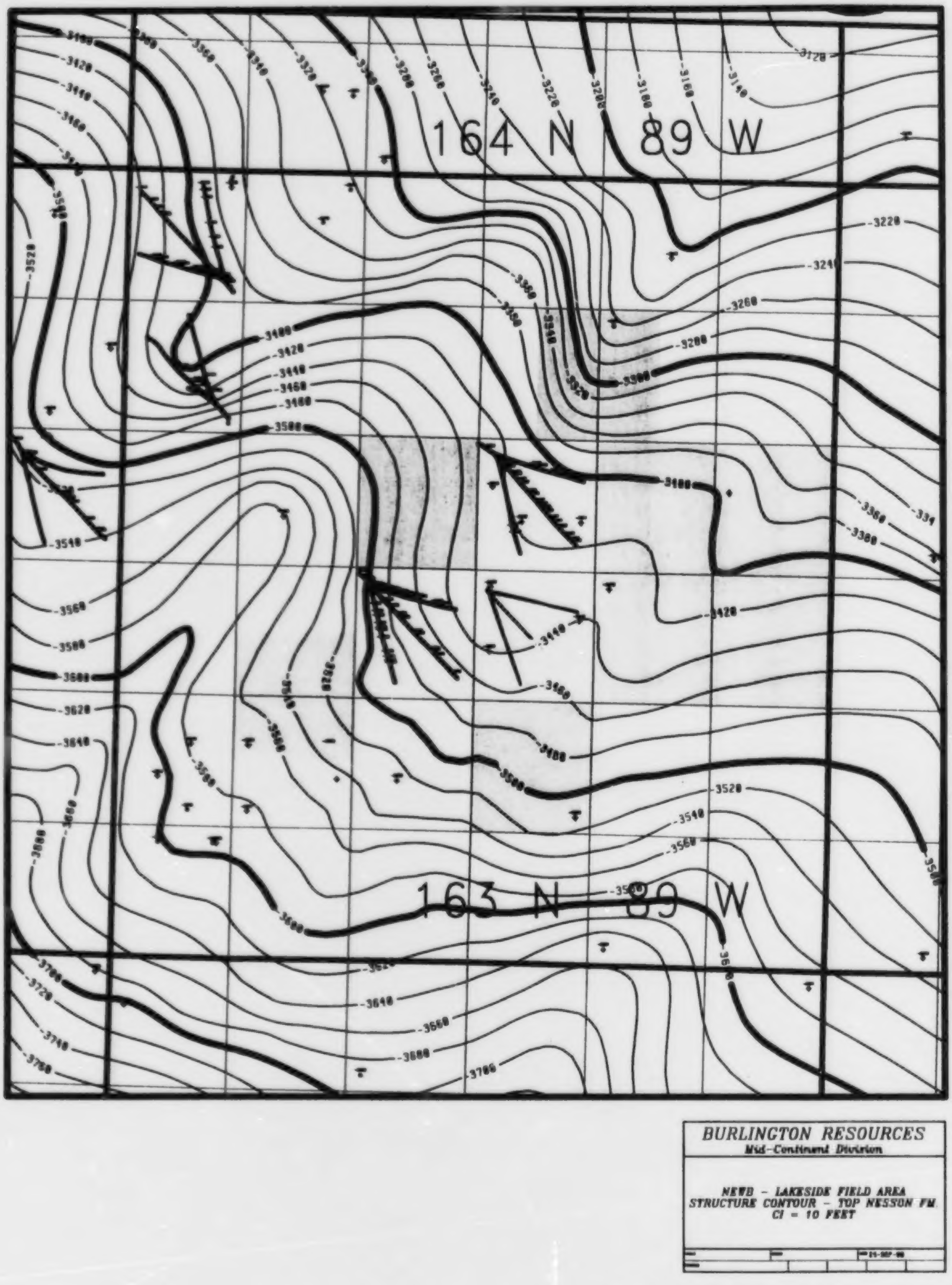


EUR vs TG (average)



STRUCTURAL POSITION VS EUR




164 N 89 W
163 N 89 W
BURLINGTON RESOURCES
Mid-Continent Division
NEWB - LAKESIDE FIELD AREA
STRUCTURE CONTOUR - TOP NESSON FM
CI = 10 FEET

SUMMARY

- **Heterogeneous Reservoir**
- **Well productivity highly variable**
- **Remaining potential in play significant**

S

Horizontal Drilling in Flaxton and Woburn Fields, Burke County, North Dakota

***Jacob D. Eisel**
Eisel Oil Company

Michael L. Hendricks
Hendricks and Associates, Inc.

BURKE COUNTY

EARLY ACTIVITY

Oil was discovered in central Burke County in July of 1957 in Lignite Field. Lignite Field produces from the Midale and Nesson intervals of the Charles and Mission Canyon Formations. Most of the production in central Burke County is from these intervals although some production was discovered in the deeper and older Coteau and Bluell intervals of the Mission Canyon Formation.

The Midale interval of the Charles Formation is a low perm, high porosity interval of dolomitic-limestone to limey dolomite twenty feet thick. Porosities range from ten percent (10%) to thirty percent (30%). The trapping mechanism is a loss of permeability. This happens to the northeast. Better permeability also appears to be controlled by structural position with the better permeability being on top of the structure. Although porosity distribution is homogenous, permeability distribution is very heterogeneous.

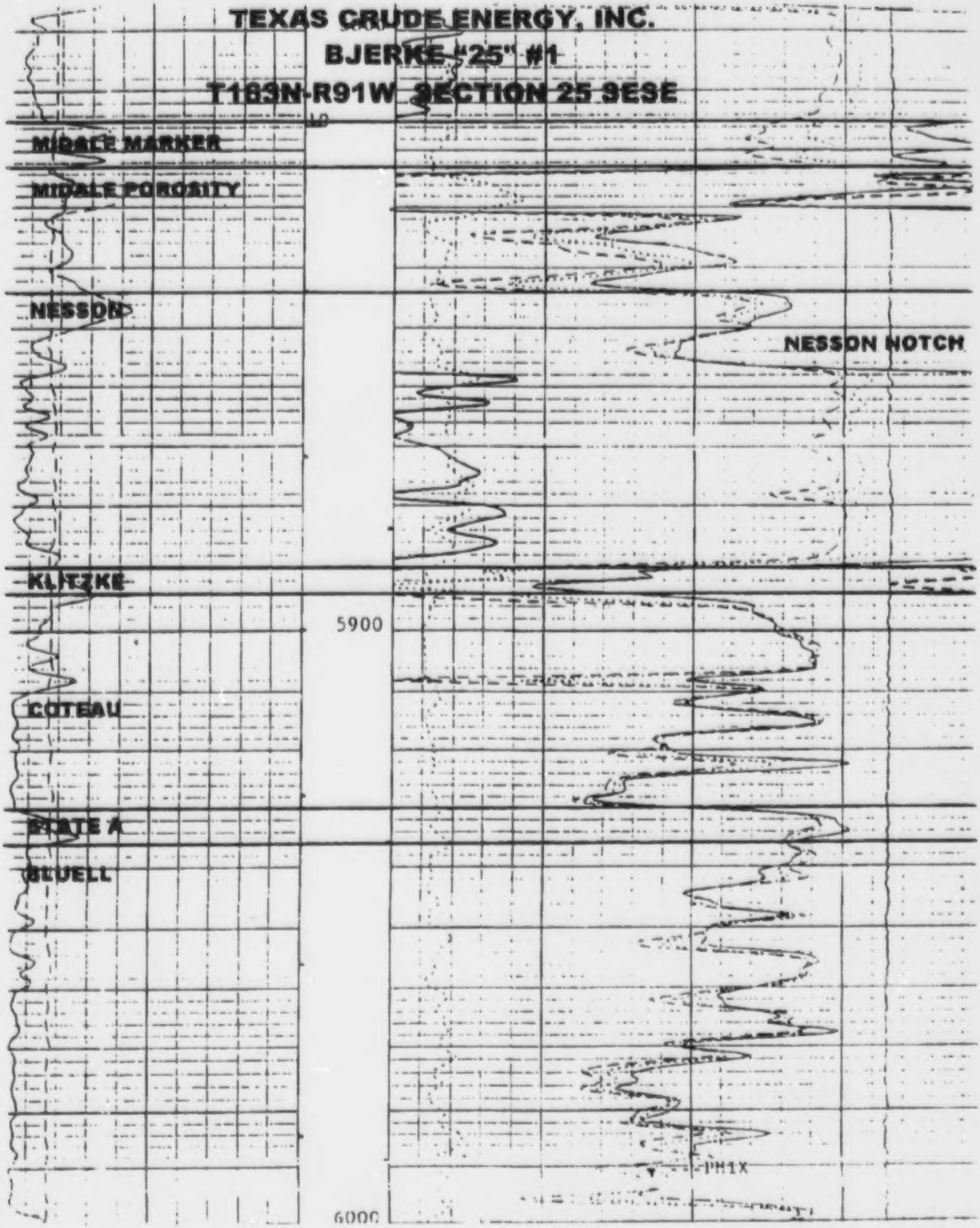
The Nesson interval of the Mission Canyon Formation is a low perm, moderate porosity interval of limestone capped by dirty anhydrite and resting on anhydrite. Porosities range from four percent (4%) to fourteen percent (14%). Permeabilities are controlled by the structures with a loss of perm to the northeast being the trapping mechanism. Production is enhanced by the presence of micro-fractures to aid the low permeability. These fractures are also controlled by the structures. Permeability distribution is very heterogeneous.

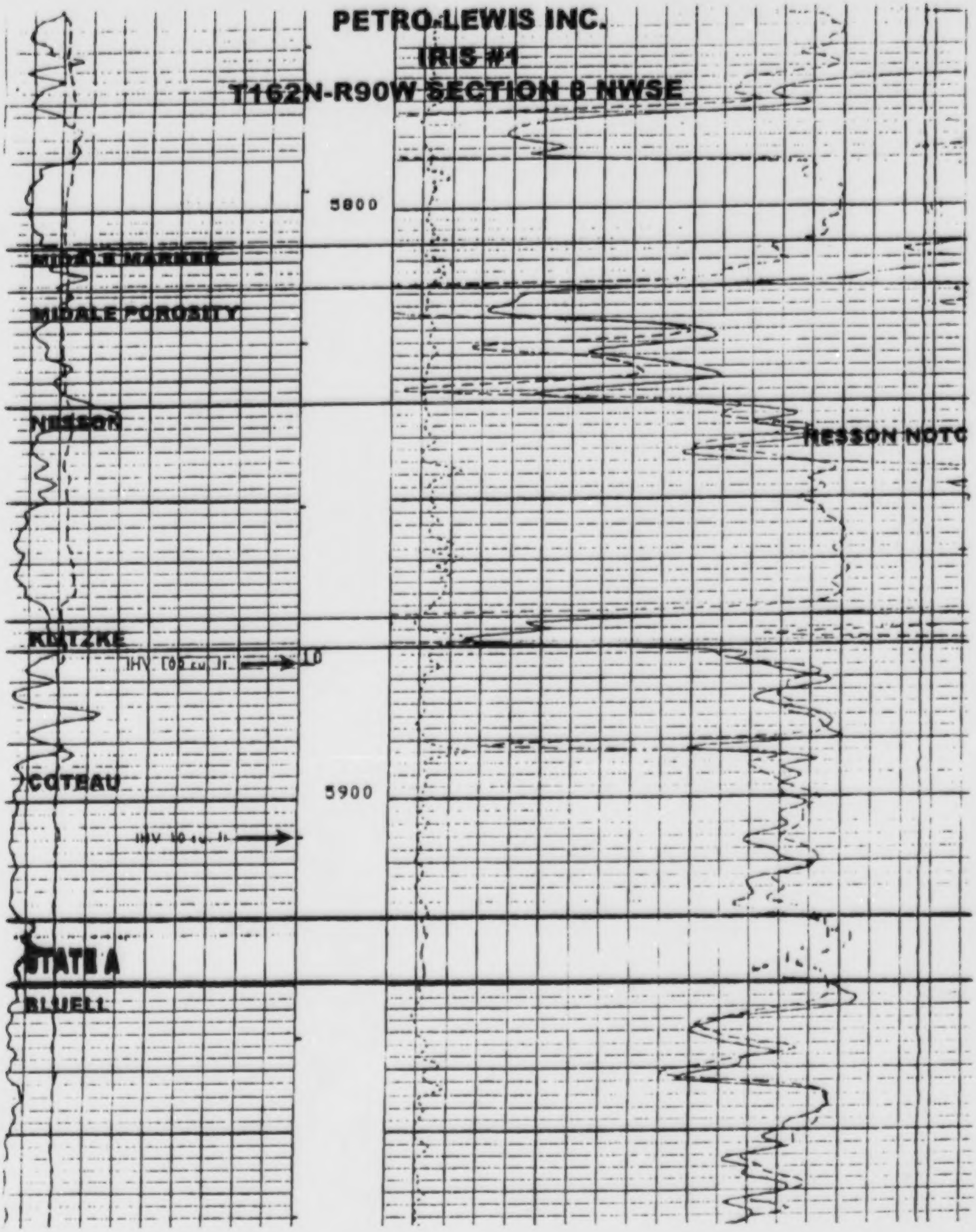
Lignite Field is the oldest Midale-Nesson producing field in the project area. It was discovered in 1957 with several wells still producing today. The field was developed on eighty (80) acre spacing to try and exploit the low perm carbonates. In most of the wells both the Midale and Nesson intervals were perforated although some wells were just perforated in the Midale and some but not many wells were just perforated in the Nesson. Production for one-hundred-sixty (160) acres ranges from two-hundred-thousand (200,000) barrels of oil to over four-hundred-thousand (400,000) barrels of oil. These production figures are somewhat biased by the fact that many of the wells were shut-in or turned into injection wells in the early 1970's when the field was unitized for the purpose of a water flood. Most of these wells were never put back on production, thus greatly restricting their total production. The water flood project was a failure due either to the heterogeneity of the reservoir or to lack of effort. Lignite Field has produced three-million-one-hundred-thousand (3,100,000) barrels of oil through 1997 from thirty-five (35) wells. Many of the producing wells had a very short productive life due to the failed water flood attempt.

Many of the other Midale-Nesson producing fields in central Burke County (Portal Field, Flaxton Field, East Flaxton Unit and Woburn Field) were developed on one-hundred-sixty (160) acre spacing. Most of the wells in these fields were only perforated in the Nesson interval even though core data indicated that the Midale interval should be productive. Woburn Field for example has produced one-million-eight-hundred-thousand (1,800,000) barrels of oil from twenty (20) wells. The structure and areal extent of Woburn Field and Lignite Field are about the same. Both fields have the equivalent perms and porosities in the Midale and Nesson intervals. This data indicates that significant reserves remain in Woburn Field and other fields that were developed on one-hundred-sixty (160) acre spacing and perforated only in the Nesson interval. The heterogeneity of the producing intervals is evidenced by the average production of up to four-hundred-thousand (400,000) barrels of oil per one-hundred-sixty (160) acres with eighty (80) acre well spacing.

RECENT ACTIVITY

Recently Burlington Resources entered the area and has begun exploiting the tight Midale-Nesson interval using horizontal drilling technology. They have had varied success mainly due to drilling philosophy. Production ranges from fifty (50) barrels of oil per day to seven-hundred-fifty (750) barrels of oil per day and three-hundred (300) mcfgpd to three-million (3,000,000) cfgpd. The better wells are on structural noses and the lesser wells are in structural lows. Most of Burlington's activity has been to the northeast of the major perm barriers for both the Midale and Nesson intervals thus yielding much smaller fields in areal extent. Burlington's activity has driven land prices in the area up to two-hundred ($200) dollars per acre. Burlington is presently drilling in Burke County.


TEXAS CRUDE ENERGY, INC.
BJERKE "25" #1
T163N-R91W SECTION 25 SESE
MIDALE MARKER
MIDALE POROSITY
NESSON
NESSON NOTCH
KLITZKE
5900
COTEAU
STATE A
BLUELL
PH1X
6000


PETRO-LEWIS INC.
IRIS #1
T162N-R90W SECTION 8 NWSE
5800
MIDALE POROSITY
NESSON
NESSON NOTC
COTEAU
5900
STATE A
BLUELL

Dwights Discover CD-ROM ID: R-144304-0 Origi
Copyright 1910 Rockies Run Date: 11-Apr

State : North Dakota 5P Merid 162N - 90W - 8 nw se

County: BURKE Oper: PETRO LEWIS CORP

Field : WOBURN Compl: 01/13/1986 D D P&A

Well: IRIS #1 Last Info: 02/14/1
Ftg: 2140 fsl 2140 fel
Lat-Long by TDG: 48.870967 - 102.379745
Obj: Confidential Te Permit #: 11582 06/07/1985 API: 33-013-0112
Elev: 1958KB

Spud: 12/29/1985 Contr: Cardinal #5
TD: 6150 Glenburn

Elev: 1958KB FORMATION TOPS (Type: L=Log S=Sample V=True Vertic
(Source: H=Dwights, I=IOG, T=Govt, S=Shell, U=USGS, R=N
M=Munger, N=NDGS, B=Boyd, G=GDS, X=Proprieta

Formation	Depth	Elev	T/S	Formation	Depth	Elev
Greenhorn	3278	-1320	L H	lwr Berentson mkr	5770	-3812
Mowry	3532	-1574	L H	Midale	5806	-3848
Dakota	3836	-1878	L H	Midale por	5814	-3856
Morrison/Swift	4104	-2146	L H	Nesson	5837	-3879
Rierdon	4516	-2558	L H	State A mkr	5869	-3911
Piper	4611	-2653	L H	Bluell	5874	-3916
Piper ls	4876	-2918	L H	Sherwood arg	5918	-3960
Spearfish	5090	-3132	L H	Sherwood carb	5924	-3966
Charles	5450	-3492	L H	K-1 mkr	5988	-4030
Charles A	5496	-3538	L H	Mohall	6000	-4042
Charles B	5603	-3645	L H	K-2 mkr	6086	-4128
bs Greenpoint anhy	5664	-3706	L H	Glenburn	6138	-4180
Charles C	5738	-3780	L H	LTD	6154	-4196

Casing: 8 5/8 @ 600
Core : #1 5865- 5908 (Bluell)
cut 43 rec 40. 40 ft: Ls, f-vf xln, ool, P.P.
vugs, some cl, perm .01-.56 md, por 0.7-18.7%, oil sat 0-31.9%, Sw
9-80.5%; 3 ft: lost
#2 5908- 5962 (Sherwood)
cut & rec 54 ft:
Ls, A.A., perm .01-26 md, por 0.9-11.8%, oil sat 0-10.1%, Sw 30.1-8
DST : #1 5792- 5865 (Midale)
op 15 si 60 op 120 si 240. IF op w/2 in blo, incr to 27 in blo/5 mi
decr to 24 min blo @ end; FF op w/2 in blo, incr to 10 1/2 in blo/6
min, decr to 5 in blo @ end. Rec 88 ft mud w/oil spks 265 ft SWCM 8
ftMCW; Smplr: 0.6 CFG @ 100 psi 1900 cc MCW. HP 3066-3025 FP 89-78
131-199 SIP 1654-2039 BHT 160 F
#2 5860- 5922 (Bluell/Sherwood)
Straddle test. Op 30 si 105 op 180 si 300. IF op w/1/4 in blo, incr
14 in blo @ end; FF op w/3/4 in blo, incr to 23 in blo/60 min, decr
22 in blo/90 min, incr to 30 in blo @ end. Rec rev circ 231 ft GO&M
534 ft GCW w/tr oil; Smplr: 0.5 CFG @ 165 psi 86.5 cc oil 34.5 cc B
1604 cc wtr. HP 3074-3038 FP 95-119 209-338 SIP 2507-2496
Logs : DLL-MSFL-GR-Cal FDC-CNL-GR-Cal BHC-Sonic-GR-Cal Cyberlook

S-6 153,398 OIL 12,708 WTR .077

CA-21

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company SIMCOX OIL COMPANY Formation AS NOTED File RP-7-401
Well GEHRKE # 1 Core Type DIAMOND Date Report 11-23-60
Field WOBURN Drilling Fluid GYP BASE MUD Analysts B. E. EVITT
County BURKE State N. DAKOTA Elev. 1959' KB Location SE SW SEC. 8 - 162N - 90W

Lithological Abbreviations

SAND-SD, SHALE-SH, LIME-LM, DOLOMITE-DOL, CHERT-CH, GYPSUM-GYP, ANHYDRITE-ANHY, CONGLOMERATE-CONG, FOSSILIFEROUS-FOSS, SANDY-SDY, SHALY-SHY, LIMY-LMY, FINE-FN, MEDIUM-MED, COARSE-CSE, CRYSTALLINE-XLN, GRAIN-GRN, GRANULAR-GRNL, BROWN-BRN, GRAY-GY, VUGGY-VGY, FRACTURED-FRAC, LAMINATION-LAM, STYLOLITIC-STY, SLIGHTLY-SL/, VERY-V/, WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE: OIL	RESIDUAL SATURATION PER CENT PORE: TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
	MIDALE FORMATION					
1	5828-29	0.1	7.4	24.3	56.7	Limestone
2	5829-30	0.5	25.8	23.7	34.9	Limestone
3	5838-39	0.2	14.6	21.2	36.3	Limestone
4	5839-40	<0.1	8.4	23.8	48.8	Limestone
5	5840-41	2.2	22.1	25.4	47.5	Limestone
6	5841-42	3.8	25.3	28.8	34.6	Limestone
7	5842-43	6.8	26.2	22.5	46.1	Limestone
8	5843-44	0.7	20.5	27.3	35.2	Limestone
9	5844-45	1.1	16.6	25.3	37.3	Limestone
10	5845-46	0.2	17.5	24.0	34.3	Limestone
11	5846-47	0.1	15.1	19.2	41.7	Limestone
12	5847-48	0.7	22.7	24.2	40.1	Limestone
13	5848-49	2.2	25.5	29.0	32.9	Limestone
14	5849-50	2.3	28.6	24.8	38.1	Limestone
15	5850-51	0.7	23.8	24.4	33.6	Limestone
16	5851-52	<0.1	8.2	19.5	32.9	Limestone
17	5852-53	0.1	6.8	14.7	52.0	Limestone, fossiliferous
	NESSON FORMATION					
18	5854-55	2.5	6.8	22.0	25.0	Limestone
19	5855-56	0.1	7.1	35.2	32.4	Limestone
20	5856-57	<0.1	~~2.8~~	~~21.4~~	46.4	Limestone
21	5857-58	0.7	13.1	26.7	25.2	Limestone
22	5858-59	0.4	16.1	32.3	17.4	Limestone
23	5859-60	1.3	14.7	23.1	21.8	Limestone
24	5860-61	0.1	9.6	30.2	18.8	Limestone

SERVICE NO. 8 NO INTERPRETATION OF RESULTS

115,166 OIL 12,296 WTR

.0964

CL-611-1

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

Page No ____

CORE ANALYSIS RESULTS

Company GOPOR OIL, INC., & STAR DRILLING, INC. Formation MIDALE & NESSON File RP-7-895
Well NO. E AAGE CHRISTIANSEN Core Type DIA. CONV. Date Report 3-9-64
Field WOBURN Drilling Fluid STARCH-10% OIL Analysts DBRNDT
County BURKE State N.D. Elev. 1928 KB Location NW NW Sec. 3 T162N R90W

Lithological Abbreviations

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS K_1	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER		SAMPLE DESCRIPTION AND REMARKS
							MIDALE
1	5678-79	0.04	15.9	7.6	66.6		Lm dolo f xln-chky shly
2	5679-80	0.06	15.0	18.0	44.7		Lm dolo suc-chky argil
3	5680-81	0.08	13.3	18.1	37.6		Lm as above
4	5681-82	<0.01	6.8	13.2	48.5	VF	Lm as above
5	5682-83	0.01	11.0	25.4	32.7	VF	Lm dolo suc-f xln calc incl
6	5683-84	0.03	9.6	21.9	35.4		Lm dolo suc argil calc incl
7	5684-85	0.01	10.9	26.6	25.8		Lm dolo suc-chky argil carb
8	5685-86	0.32	17.2	19.2	40.7		Lm suc argil
9	5686-87	0.58	16.0	27.5	33.8		Lm suc-f xln argil scat nodul
10	5687-88	0.36	15.8	24.0	28.5		Lm suc-chky argil calc incl
11	5688-89	0.11	10.4	11.5	37.5		Lm dolo f xln argil
12	5689-90	0.02	9.8	9.2	59.2		Lm dolo f xln-chky argil
13	5690-91	0.08	13.9	13.0	43.8		Lm as above
14	5691-92	0.20	19.1	24.6	37.7		Lm dolo suc-f xln argil
15	5692-93	0.65	23.7	19.8	42.2		Lm as above
16	5693-94	0.34	21.3	21.6	45.1		Lm dolo f xln-chky argil
17	5694-95	<0.01	8.8	8.0	62.5		Lm as above
18	5695-96	<0.01	3.2	28.1	37.5		Lm dolo xln argil foss carb
							NESSON
19	5698-99	<0.01	4.5	20.0	17.8		Lm xln scat pelletoids
20	5699-5700	0.01	3.0	16.7	30.0		Lm f xln pelletoidal
21	5700-01	0.11	6.4	18.7	37.5		Lm algal piso ool pp vugs
22	5701-02	<0.01	2.8	17.8	60.7	VF	Lm f xln algal piso ool
23	5702-03	0.50	12.7	21.2	32.2	VF	Lm algal piso pellet scat vug
24	5703-04	0.79	10.7	23.4	29.0	VF	Lm as above
25	5704-05	2.7	14.4	18.1	25.0	VF	Lm f xln scat pellet pp vugs
26	5705-06 perf	3.8	13.9	19.4	30.2	VF	Lm as above
27	5706-07	0.01	7.9	20.2	31.6	VF	Lm f xln scat pellet carb
28	5707-08	<0.01	5.9	27.1	27.1	VF	Lm f xln anhy

SERVICE NO. 8. VF = VERTICAL FRACTURE

S-8 241,433 OIL 20,767 WTR .079

CA 10

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

Page No._____

CORE ANALYSIS RESULTS

Company SIMCOX OIL COMPANY Formation AS NOTED File RP-7-359
Well #1 GRADX Core Type DIAMOND Date Report 7/10/60
Field WOBURN Drilling Fluid GYP BASE MUD Analysts EVITT
County BURKE State N. DAK. Elev. 1939'GR Location SE NE 7-162N-90W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
MIDALE						MIDALE FORMATION
1	5804-05	3.3	32.3	22.6	31.6	Dolomite, argillaceous
2	5805-06	10	28.4	17.6	27.1	Do lomite, argillaceous
3	5806-07	0.9	22.7	24.2	27.3	Limestone
4	5807-08	0.2	14.1	24.8	29.1	Limestone
5	5808-09	0.4	15.4	23.4	26.0	Limestone
6	5809-10	0.6	20.8	28.4	30.3	Limestone
7	5810-11	2.2	24.5	29.8	32.7	Limestone
8	5811-12	0.1	16.6	21.7	34.4	Limestone
9	5812-13	0.7	19.7	29.0	29.0	Limestone
10	5813-14	5.5	27.1	18.8	33.6	Limestone
11	5814-15	7.4	28.4	16.2	32.1	Limestone
12	5815-16	0.3	17.2	16.9	41.3	Limestone
13	5816-17	0.5	17.8	28.1	32.6	Limestone
14	5817-18	2.2	28.0	25.0	37.5	Limestone
15	5818-19	0.2	12.0	6.7	58.3	Limestone
16	5819-20	1.9	27.0	27.4	28.5	Limestone
17	5820-21	4.2	29.5	29.2	27.4	Limestone
18	5821-22	<0.1	4.4	22.7	50.0	Limestone, fossiliferous
19	5822-23	<0.1	4.2	0.0	21.5	Limestone, fossiliferous
20	5823-24	<0.1	8.7	11.5	47.0	Limestone, fossiliferous
21	5824-25	0.1	5.7	10.5	22.8	Limestone, NESSON FORMATION
22	5825-26	0.4	8.2	17.1	24.4	Limestone
23	5826-27	<0.1	2.3	0.0	56.5	Limestone
24	5827-28	0.2	5.0	36.0	32.0	Limestone
25	5828-29	0.1	12.0	24.2	19.2	Limestone
26	5829-30	0.5	11.9	30.2	20.1	Limestone
27	5830-31	0.1	9.8	28.5	18.3	Limestone
28	5831-32	0.7	8.0	25.0	15.0	Limestone
29	5832-33	0.2	5.8	83.2	13.8	Limestone
30	5833-34	f 1.1	2.5	24.0	36.0	Anhydrite, Dolomite
31	5834-35	<0.1	1.0	0.0	50.0	Anhydrite, Dolomite
32	5835-36	<0.1	1.0	0.0	20.0	Anhydrite, Dolomite
33	5836-37	f 1.5	12.9	33.3	24.1	Anhydrite, Dolomite

f - indicates fracture in perm plug.

BURKE COUNTY INFILL PROJECT ECONOMICS

Well cost for a multi-lateral is estimated to be seven-hundred-thousand dollars ($700,000). If the estimated total of sixty-five wells is drilled, well cost may decrease to six-hundred-thousand dollars ($600,000). The oil is thirty-nine to forty-one gravity sweet. Crude oil is purchased by Murphy Oil Corporation at the Williston Basin Sweet price with no gravity deductions plus a one dollar and twenty-five cent ($1.25) bonus. This oil price greatly enhances the economics of the project.

ESTIMATED RETURNS ON A PER WELL BASIS

RESERVES bbls	$/bbl	REVENUE $	WELL COST $	RETURN $
50,000	10	500,000	-700,000	-200,000
50,000	13	650,000	-700,000	-50,000
50,000	15	750,000	-700,000	50,000
50,000	18*	900,000	-700,000	200,000
50,000	20	1,000,000	-700,000	300,000
50,000	23	1,150,000	-700,000	450,000
50,000	25	1,250,000	-700,000	550,000
50,000	28	1,400,000	-700,000	700,000
50,000	30	1,500,000	-700,000	800,000
100,000	10	1,000,000	-700,000	300,000
100,000	13	1,300,000	-700,000	600,000

100,000	15	1,500,000	-700,000	800,000
100,000	18*	1,800,000	-700,000	1,100,000
100,000	20	2,000,000	-700,000	1,300,000
100,000	23	2,300,000	-700,000	1,600,000
100,000	25	2,500,000	-700,000	1,800,000
100,000	28	2,800,000	-700,000	2,100,000
100,000	30	3,000,000	-700,000	2,300,000
200,000	10	2,000,000	-700,000	1,300,000
200,000	13	2,600,000	-700,000	1,900,000
200,000	15	3,000,000	-700,000	2,300,000
200,000	18*	3,600,000	-700,000	2,900,000
200,000	20	4,000,000	-700,000	3,300,000
200,000	23	4,600,000	-700,000	3,900,000
200,000	25	5,000,000	-700,000	4,300,000
200,000	28	5,600,000	-700,000	4,900,000
200,000	30	6,000,000	-700,000	5,300,000
300,000	10	3,000,000	-700,000	2,300,000
300,000	13	3,900,000	-700,000	3,200,000

300,000	15	4,500,000	-700,000	3,800,000
300,000	18*	5,400,000	-700,000	4,700,000
300,000	20	6,000,000	-700,000	5,300,000
300,000	23	6,900,000	-700,000	6,200,000
300,000	25	7,500,000	-700,000	6,800,000
300,000	28	8,400,000	-700,000	7,700,000
300,000	30	9,000,000	-700,000	8,300,000
400,000	10	4,000,000	-700,000	3,300,000
400,000	13	5,200,000	-700,000	4,500,000
400,000	15	6,000,000	-700,000	5,300,000
400,000	18*	7,200,000	-700,000	6,500,000
400,000	20	8,000,000	-700,000	7,300,000
400,000	23	9,200,000	-700,000	8,500,000
400,000	25	10,000,000	-700,000	9,300,000
400,000	28	11,200,000	-700,000	10,500,000
400,000	30	12,000,000	-700,000	11,300,000

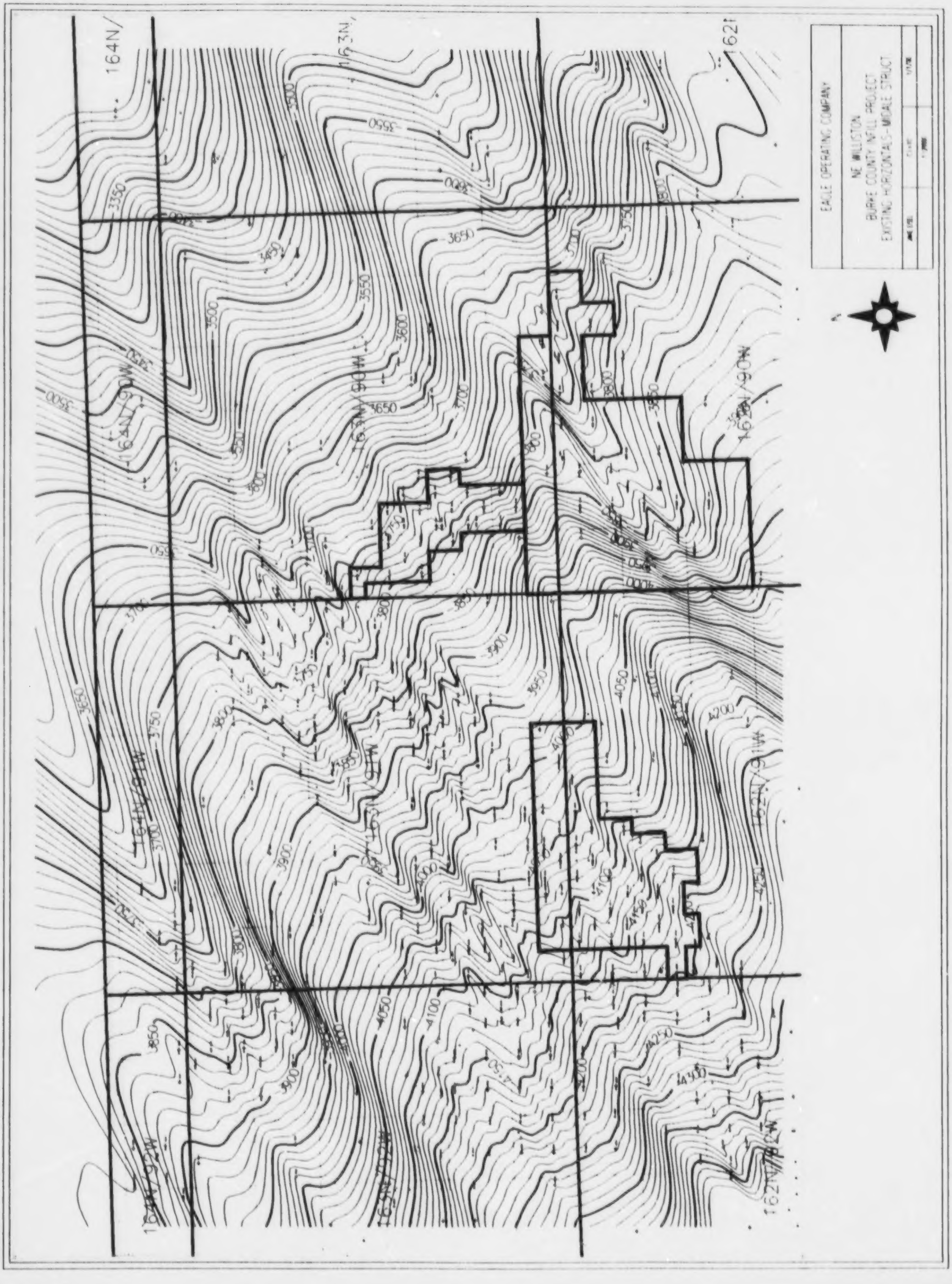
* STATISTICAL AVERAGE PRICE PER BARREL

Additional revenue will be generated by gas sales. Gas pipe lines are already in place. It is estimated that each well will make three-hundred to five-hundred mcf per day. At seventy-five

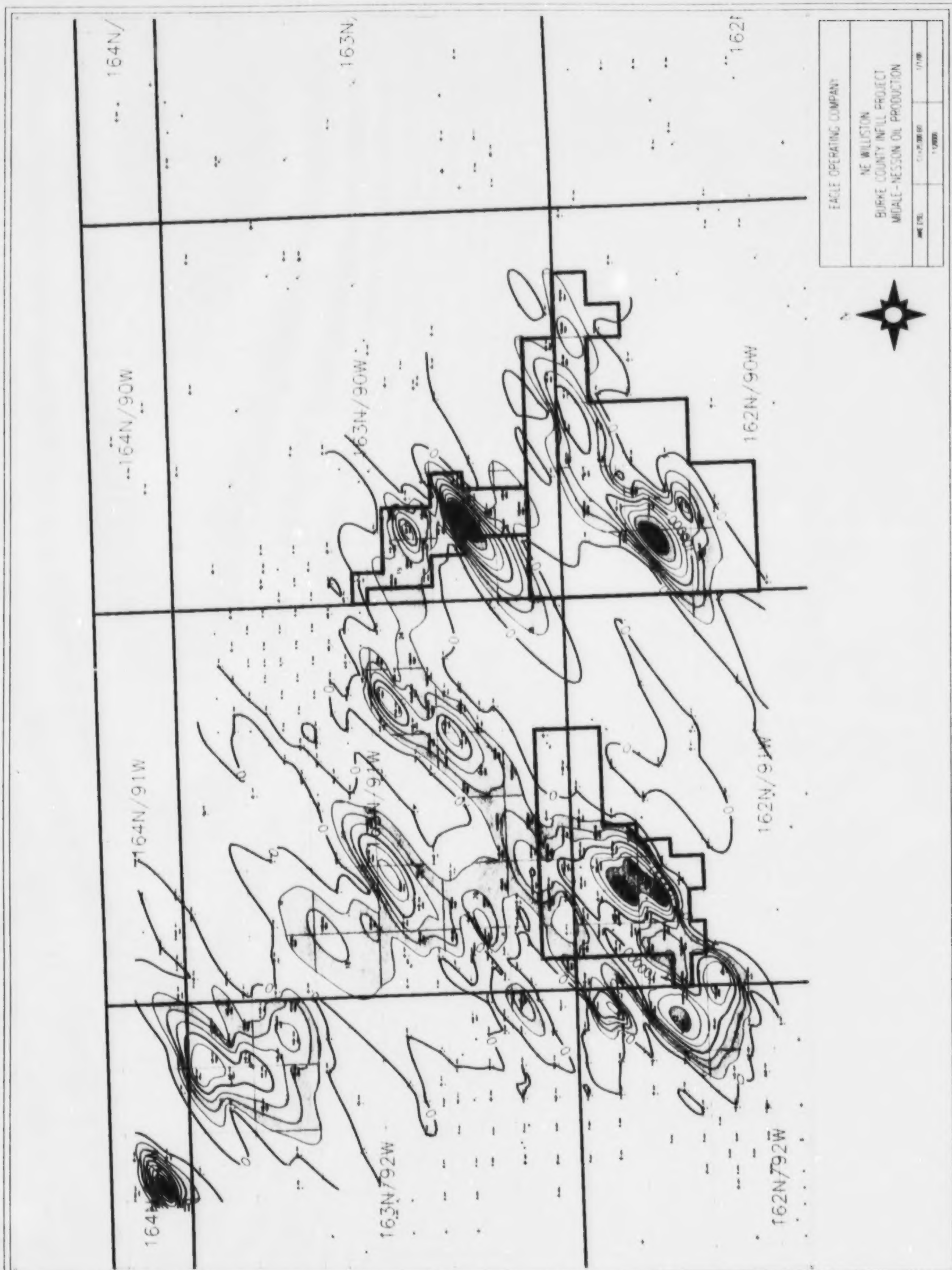
cents ($0.75) per mcf, each well will generate another six-thousand-seven-hundred-fifty dollars ($6,750) to eleven-thousand-two-hundred-fifty dollars ($11,250) per month. This should more than cover operating costs.

Well payout; using three-hundred (200) BOPD, ten dollars ($10) per barrel and six-hundred-thousand dollars ($700,000) for well costs, should be in less than twelve months not including gas sales..

The potential for secondary recovery in the project area is greatly enhanced by the construction of a CO_2 gas pipeline from Beulah, North Dakota to Midale Field in Saskatchewan, Canada which will pass just west of the project area.



EAGLE OPERATING COMPANY
NE WILLISTON
BURKE COUNTY INFILL PROJECT
EXISTING HORIZONTALS-MIDALE STRUCT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NE WILLISTON
BURKE COUNTY INFILL PROJECT
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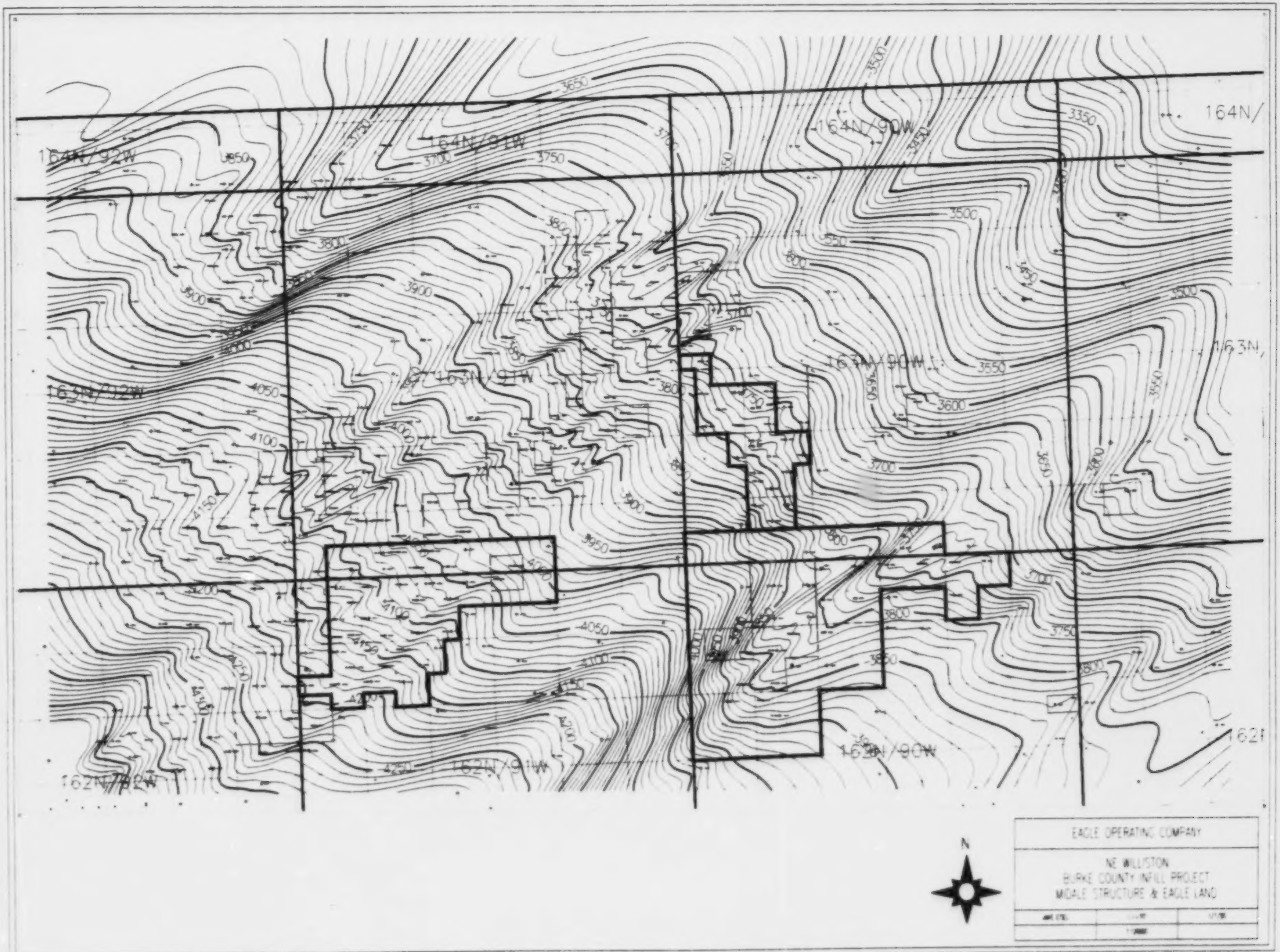

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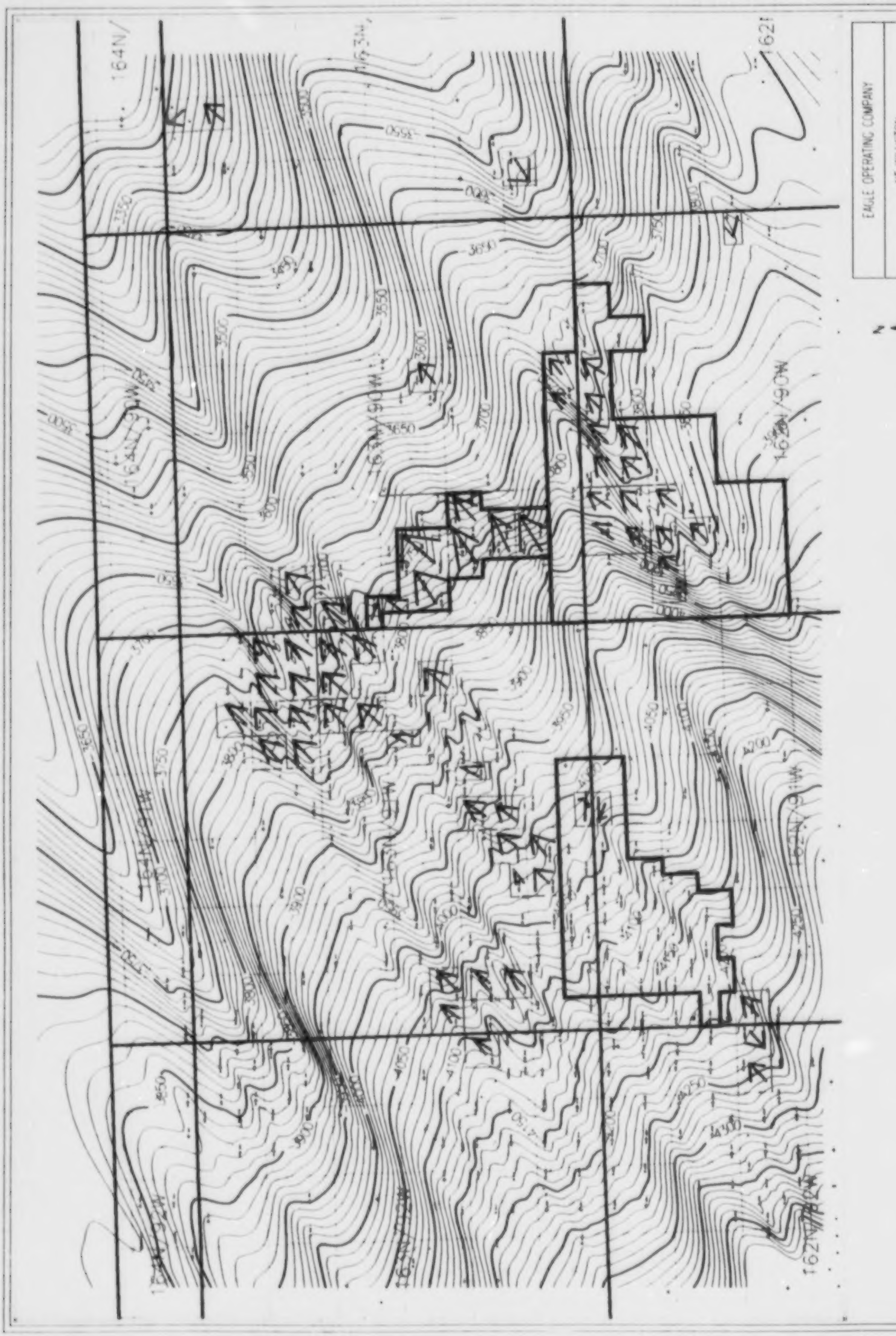
BURKE COUNTY INFILL PROJECT
MIDALE STRUCTURE & EAGLE LAND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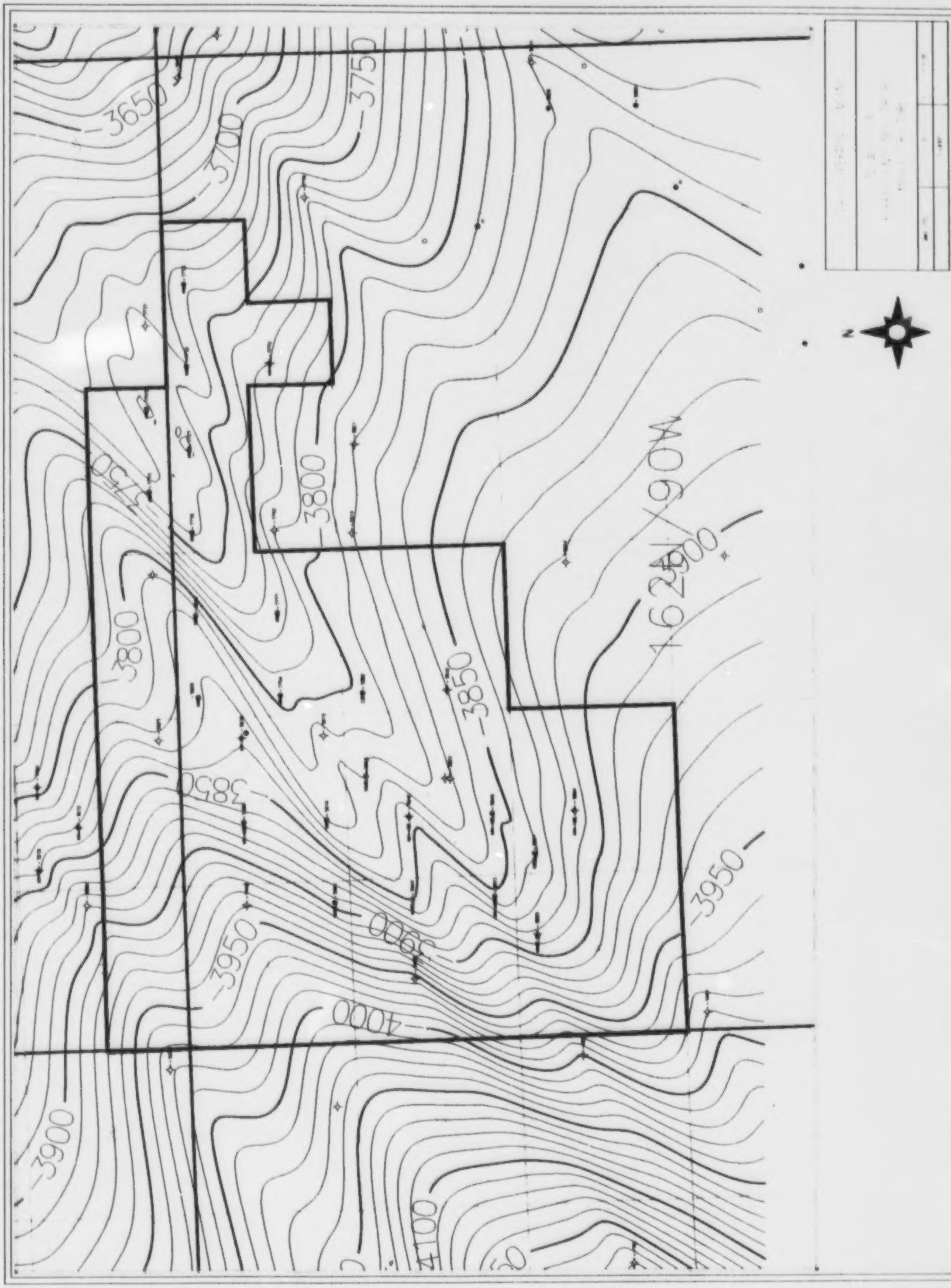
BURKE COUNTY INFILL PROJECT
PROPOSED HORIZONTALS & EAGLE LAND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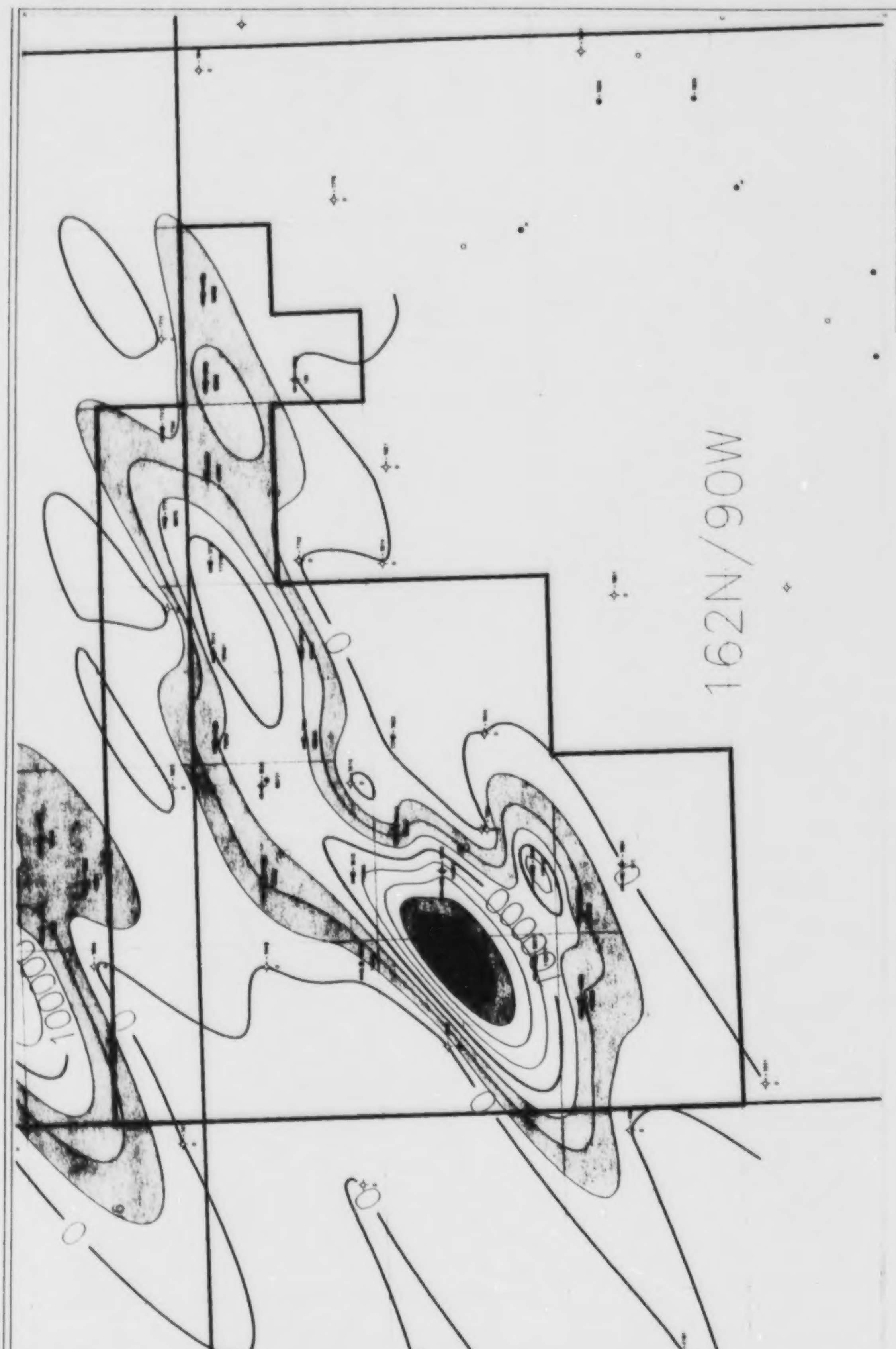
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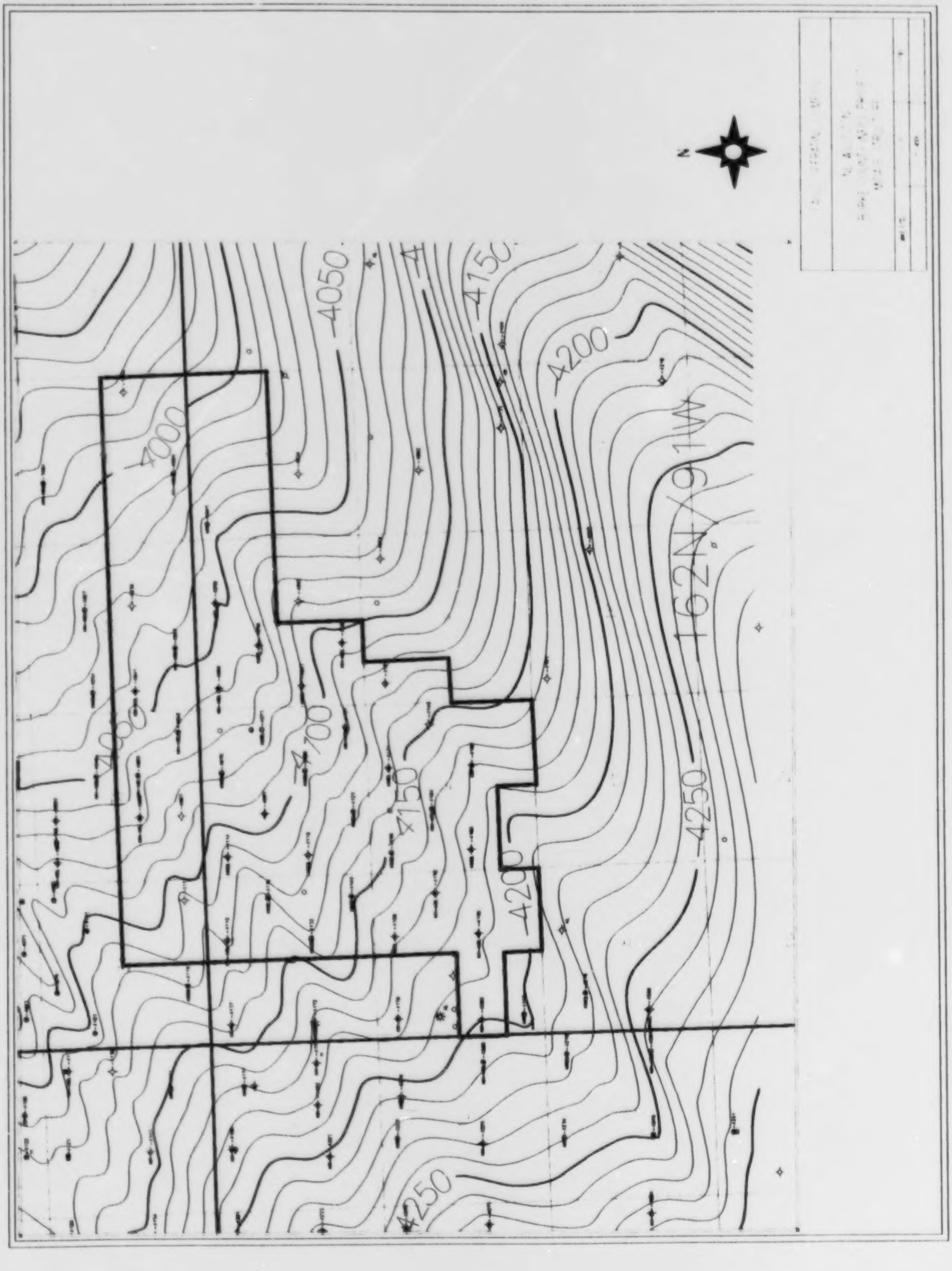
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EAGLE OPERATING COMPANY
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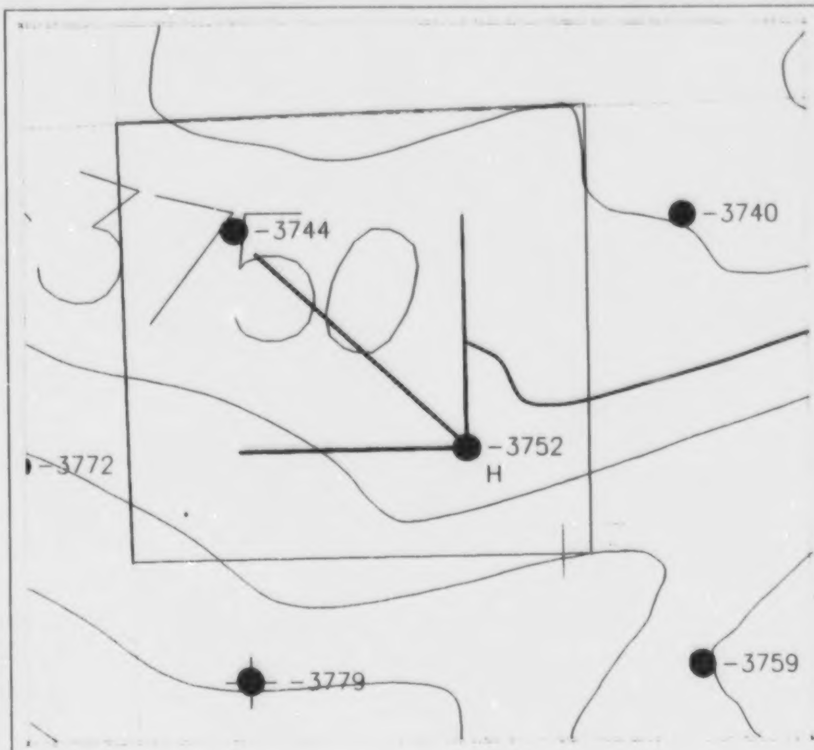
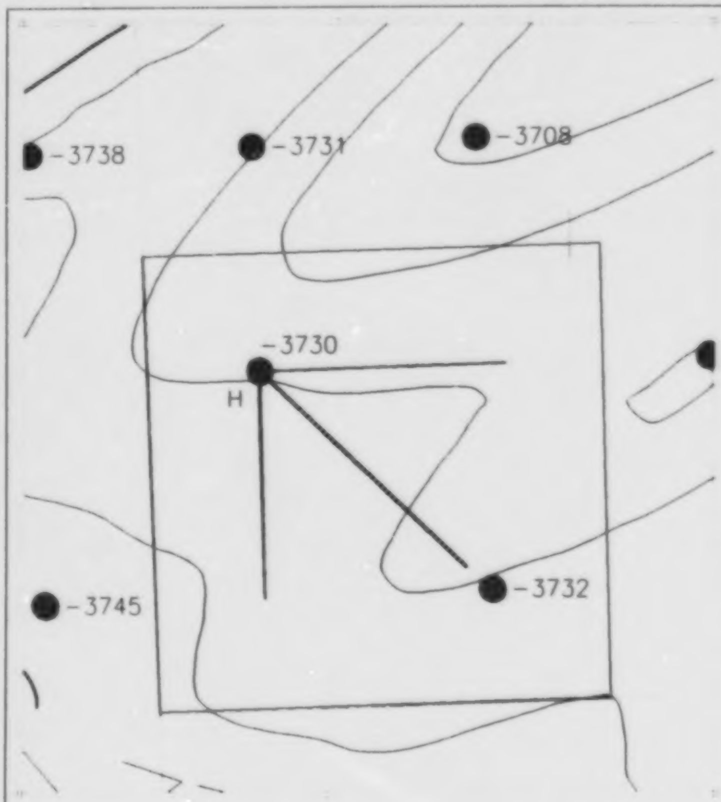
BURKE COUNTY INFILL PROJECT
MIDALE-NESSON OIL PRODUCTION
162N/91W



EAGLE OPERATING, INC.

BURKE COUNTY HORIZONTAL PROJECT
SORUM #1 HORIZONTAL T-163-N R-91-W
STRUCTURE with PROPOSED HORIZONTAL

JAKE EISEL	C.I.=10'	11/15/99
CASE # 7310	1"=1000'	EXHIBIT #5



EAGLE OPERATING, INC.

BURKE COUNTY HORIZONTAL PROJECT
MARVIN #2 HORIZONTAL T-163-N R-91-W
STRUCTURE with PROPOSED HORIZONTAL

JAKE EISEL	C.I.=10'	11/15/99
CASE # 7309	1"=1000'	EXHIBIT #5

T

Lower Paleozoic Exploration Potential Williston Basin

*John C. Horne
Orion International Limited

*Richard F. Inden
LSSI

INTRODUCTION

Interest in the potentially significant oil and gas reserves from the Williston basin Winnipeg and Deadwood formations is increasing due to the recent high flow rates established in the Midale area in the Canadian portion of the basin. Most of the activity to present has concentrated on leasing and drilling in the near vicinity of these discoveries. The high flow rates, along with other data, suggest that major fault systems and fractures play a critical role in establishing significant production in these lower Paleozoic formations. These successes and the intriguing potential of the Newporte area have sparked new interest in the United States portion of the Williston basin.

Inherited Precambrian basement fault systems in basins such as the Williston often are reactivated by later tectonic events throughout the Phanerozoic. These faults influence the development of present-day structural patterns and fracture trends. They also affect depositional trends, facies patterns, and the migration and entrapment of hydrocarbons within the basin.

In the Williston basin, lower Paleozoic fault block trends follow the strong magnetic signatures of the underlying Precambrian basement. During the Cambrian and early Ordovician, some of the Precambrian fault trends were re-activated by tectonic activity in the cordilleran to the west. These fault trends affected the development of topographic relief on the Precambrian surface and subsequent development of structural closures and hydrocarbon migration paths in the lower Paleozoic strata. Movements on these Precambrian faults and more subtle fracture trends exerted a strong control on the distribution and orientation of reservoir-potential valley-fill deposits and strandline to shallow marine sandstones in the Deadwood as well as the thickness distribution of the Winnipeg Black Island Garland sandstones.

REGIONAL SETTING

During Late Cambrian time, Phanerozoic deposition began in the area of the present-day Williston Basin as shallow marine water transgressed from the west (Gerhard et al., 1982). At that time, the basin was a large embayment on the western Cordilleran shelf (Gerhard et al., 1982) of the foreland seaway. Marine transgressions entered the basin from the west, flooding the northern, eastern, and southern margins of the basin numerous times. Several fluctuations in sea level occurred in this overall transgressive sequence. The Deadwood Formation was deposited as an onlapping sequence of clastics over the irregular and hilly surface of the Precambrian. During this interval of time, lowstand unconformities and fluvial-estuarine valley-fill deposits were more prevalent in the shallower marginal parts of the basin.

Thickness and type of sediments that accumulated in the Deadwood were controlled strongly by basement block highs and the relative position of sea level.

Some of the larger basement block highs controlled sediment distribution well into the Ordovician. In general, Deadwood sediments are dominantly marine and finer grained in the western part of the Williston basin and become coarser grained to the east, north, and south. They are dominated by basinal facies in the west and storm-dominated shelf facies to the east. However, in areas removed from terrigenous clastic sediment influx, carbonate shelf deposits accumulated.

The Deadwood Formation is a dominantly clastic sequence as much as 900 feet thick in eastern Montana. The formation comprises basal sandstones overlain by shale and carbonate, which, in turn, are overlain by another sandstone. Capping the upper sandstone is a carbonate unit that accounts for most of the increased thickness in western North Dakota (Carlson and Anderson, 1965). The basal clastic part of the formation includes a considerable amount of reworked, weathered Precambrian material. It was deposited in nearshore and shelf environments (Gerhard et al., 1982; Thompson, 1984). The carbonates were deposited in an offshore marine setting (Thompson, 1984). Although the erosional limit of the Deadwood Formation is in eastern North Dakota, the original depositional limits may have extended a considerable distance farther (Carlson and Anderson, 1965).

Toward the latter part of the Cambrian and into the Early Ordovician, access to the western foreland seaway was cut-off either by thrusting in the foreland and/or by the development of a peripheral bulge. This structural inversion along the western margin of the Williston basin restricted the access of marine waters into the basin from the west. It represents the early stages of development of the Elk Point basin with later Paleozoic transgressions entering the Williston basin from the north.

When the sea withdrew at the end of Deadwood sedimentation, a major erosional unconformity developed truncating the top of the formation. Most of the Ordovician Winnipeg deposits record a major transgressive event over a basinwide unconformable surface. However, in the more rapidly subsiding center of the basin, there are two unconformities with an isolated erosional remnant of the lower part of the Winnipeg. These Winnipeg, Black Island, Hawkeye deposits represent an earlier transgressive sequence largely removed by the upper unconformity.

Over the upper unconformity are the transgressive deposits of the Black Island Garland member of the Winnipeg. These deposits accumulated during a relative sea level rise and record the deepening of the waters in the basin. Energy conditions decrease upward through the Garland. The decrease in primary sedimentary structures and grain size in the sandstones reflect the diminishing energy conditions. Accompanying the decrease in primary sedimentary structures is a significant increase in biogenic and diagenetic features such as burrowing and early-cemented hardgrounds.

Ultimately, the sandstones of the Garland grade upward into the deeper water shales of the Winnipeg Icebox. In many areas, the Icebox shales exhibit very little burrowing and the preservation of Graptolites and phosphatic brachiopods indicating poor circulation and anoxic bottom conditions in the basin during this interval of time. The organic content of the Icebox shales suggests they may be a significant source for Winnipeg and Deadwood hydrocarbon accumulations. The upper part of the Icebox shales transition into the overlying carbonates of the Red River. This transition zone is the Roughlock member of the Winnipeg.

Preliminary analyses of samples from the Icebox shale interval and interbedded sandstone and shale sequences of the Black Island and Deadwood intervals indicate that thermally mature source rocks are present in a number of localities across the Williston basin. Rock evaluation analyses show significant volumes of dark gray and black shales have TOCs up to 4.36%. Tmax values range from greater than 500^0 C. in the central deeper portions of the basin to 440^0-450^0 C. towards the flanks. This suggests the central portions of the basin are in the wet/dry gas generation range, while the flanks of the basin are in the peak oil generation window.

NEWPORTE AREA

Previous research on the lower Paleozoic production in the Newporte area has suggested two alternative explanations for the origin of the Newporte structure. Clement and Mayhew (1979) and Gerlach and others (1995) indicated the Newporte structure was the result of meteor impact. However, Hendricks (1999) concluded the Newporte feature was a basement block high that was active during deposition of the lower Paleozoic strata and rejuvenated by subsequent tectonism causing structural drape affecting hydrocarbon entrapment.

If the meteor impact hypothesis is correct, the Newporte structure is unique. However, the basement block high hypothesis opens the potential for other Precambrian highs having hydrocarbon accumulations over and adjacent to these features. The greatest potential exists around basement highs along select tectonic trends that were active during Cambrian and Ordovician time. Subsequent drape over these basement highs created structural closure forming hydrocarbon entrapment capacity over time.

Recent aeromagnetic investigations suggest the Newporte feature developed as the result of structural movements along a major regional northeast-oriented wrench fault system that was active during late Precambrian to Ordovician time. This fault and numerous others gave rise to a series of regional paleo-highs and paleo-lows that influenced the development of

Cambrian and Ordovician accommodation space as well as depositional patterns of the Winnipeg and Deadwood sediments.

Interestingly, this fault transects a large diameter (~30 miles), multi-tiered, circular aeromagnetic feature that predates the wrench fault motion. Indications are that this circular feature developed in the Precambrian and may be the result of a meteor impact event. This would explain the origin of the shattered stressed quartz grains observed by Gerlach and others (1995) in the Cambrian and Ordovician sandstones from the Newporte area. These Deadwood and Winnipeg sandstones should contain stress shattered quartz grains eroded locally from the Precambrian basement block high. Thus, the Precambrian meteor impact event has little to do with the occurrence of hydrocarbons in the Newporte area.

CONCLUSIONS

- Source potential shales are present in the Winnipeg and Deadwood formations with TOCs over 4.0%. They are in the wet/dry gas generation window in the deeper central parts of the basin and in the oil generation window along the flanks.

- Hydrocarbon exploration potential in the Winnipeg and Deadwood formations is associated with Precambrian basement block highs. They provide the structural closure with post-depositional movements and/or compactional drape.

- In most instances, exploration potential in the Deadwood sandstones is greatest along the flanks of the basement block highs, whereas the crest of the block highs generally have the greatest potential in the Winnipeg sandstones.

- Recurrent wrench fault movements and fracturing along basement linears control the distribution of basement block highs and hydrocarbon migration paths.

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Basement Controls on Red River Sedimentation and Hydrocarbon Production in Southeastern Saskatchewan

*L. K. Kreis
Saskatchewan Energy and Mines

D. M. Kent
D. M. Kent Consulting Geologist Ltd.

Basement Controls on Red River Sedimentation and Hydrocarbon Production in Southeastern Saskatchewan

L.K. Kreis[1] and D.M. Kent[2]

Discovery of significant oil reserves in Red River strata in the Berkley et al. Midale 4-2-7-11W2 well in December 1995 has renewed interest in Red River and deeper rocks such as the Winnipeg Formation, of southeastern Saskatchewan. Prior to the Midale discovery, Red River production was restricted to 16 wells widely distributed in the Minton, Hummingbird, Lake Alma, Beaubier, Oungre, Bromhead, and Weir Hills areas, all within 60 km of the US border (Figure 1). Since then, Red River producing reservoirs have been discovered up to 75 km northward into the Chapleau Lake area, and Winnipeg production has been established in the Midale and Hartaven areas. Between December 1995 and December 1999, over 280 wells were licensed to explore the Red River in southeastern Saskatchewan. More than half of these were licensed to drill to the Precambrian.

Regional Basement Features

Three major basement provinces are recognized from regional magnetic data in the Williston Basin area (Green *et al.*, 1985a, b; Baird *et al.*, 1995; Gibson, 1995; and Kreis *et al.*, 2000). Archean (>2.5 billion years) rocks of the Wyoming Province in the west and the Superior Province in the east are separated by an intervening collage of Proterozoic rocks belonging to the Trans-Hudson Orogen (1.8-1.9 billion years) (Figure 2). The Trans-Hudson Orogen is considered by Lewry and Collerson (1990) to be a major component of the Early Proterozoic Pan-American orogenic system, extending from South Dakota, across Hudson Bay, Greenland and Labrador. Results from the COCORP deep reflection seismic transect in northeastern Montana and northern North Dakota suggest that the Trans-Hudson Orogen is probably cored beneath the Williston Basin by an Archean crustal fragment that was caught up in the collision of the two Archean paleocontinents (Baird *et al.*, 1995).

Mappable features that are spatially related to the boundaries of the basement provinces and that are defined by thickness anomalies in various Phanerozoic formations or by geophysical mapping include the Birdtail-Waskada axis, a well known north-south lineament lying immediately east of the Saskatchewan-Manitoba border. It is characterized by numerous structural and stratigraphic irregularities (McCabe, 1967; Dietrich and Magnusson, 1998), and it directly overlies the boundary between the Trans-Hudson (Churchill) and Superior provinces. Andrichuk (1959), Kent (1960), Christopher (1961), Kendall (1976), and Kreis (1991) also document thinning of various Phanerozoic units in a north-south zone in southeastern Saskatchewan which parallels the Birdtail-Waskada axis and is coincidental with the Nelson River gravity trend of MacDonald and Broughton (1980) (Figure 2). Three deep wells, Imperial Lightning Creek 16-7-6-32W1, Cherokee et al. Workman

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2-34-1-32W1, and Interaction Renata Workman 3-27-1-32W1, show evidence in the Red River supporting the structural nature of the axis. The former two have repeated sections indicating thrust faulting and the latter has a thinner-than-normal succession.

The coincidence of the North American Central Plains electrical conductivity anomaly (NACP) with the Trans-Hudson Orogen implies a Precambrian basement structural control to the feature (Figure 2). The presence of high-grade metamorphic rocks in drill core samples and of a narrower width of the Trans-Hudson segment in North and South Dakota relative to the exposed segment in the Canadian Shield suggest that compression during collision was greater in the Williston Basin area (Baird *et al.*, 1995). Majorowicz *et al.* (1986, 1988) and Osadetz *et al.* (1998) discuss a heat flow anomaly that is situated near Estevan, immediately east of the NACP along 103°W (Figure 2). It juxtaposes an electrical conductivity anomaly found from a magnetotelluric (MT) study reported by Jones and Savage (1986). Both the heat flow and electrical MT conductivity anomalies coincide with a significant Williston Basin feature, the Nesson Anticline (Majorowicz *et al.*, 1988), which has been active throughout Phanerozoic history (Gerhard *et al.*, 1982).

Features that appear to be spatially related to the interpreted northeastern margin of the Wyoming Province in southeastern Saskatchewan include some predominantly northwest-trending multistage salt-solution structures and major seismic positive elements (Kent, 1973). The northeast margin of the present-day salt dissolution edge of the Prairie Evaporite is subparallel to the northeastern edge of the Wyoming Province (Figure 2), as are surficial topographic lineaments formed by Wascana Creek, Moose Jaw Creek and Souris River waterways and the northeastern edge of the Missouri Coteau (Figure 3). The Elbow-Weyburn trend (Figures 2 and 3) of Paleozoic age is also oriented northwest-southeast (Christopher, 1980).

Numerous authors have recognized Precambrian basement structural controls on sedimentation within the Williston Basin (Kent, 1973, 1974, 1987; Potter and St. Onge, 1991; Kissling, 1997). Some have described a predominance of lineaments with northeasterly and northwesterly strikes which they attribute to regional stresses in Precambrian basement rocks (Thomas, 1974; Bell and Babcock, 1986; Stauffer and Gendzwill, 1987; Brown and Brown, 1987; Penner and Mollard, 1991; Misra *et al.*, 1991; Gibson, 1995).

Local Basement Features

A spatial relationship exists between paleotopographic highs on the Precambrian crystalline basement and structural and thickness anomalies in overlying Lower Paleozoic strata such as the Deadwood and Red River formations (Figures 4 to 7). For example, the isopach map of the Deadwood Formation in southeastern Saskatchewan (Figure 4) clearly reflects areas of high relief on the Precambrian basement surface (Figure 6). A *ca.* 70 km long northeast-trending zone of thin Deadwood joining the Midale, Froude, Hartaven, Corning and Fillmore areas (Figures 1 and 8) forms the longest

Precambrian ridge-like feature discernible from current well control. These features are interpreted to be linear zones comprised of small fault blocks in an en echelon arrangement. Clastic sediments of the Deadwood Formation appear to have onlapped and infilled areas around Precambrian basement highs. Somewhat farther to the west the highest basement structure yet encountered, *ca.* 170 m, as determined from the Deadwood isopach map, appears to have been penetrated by the Amerada Crown S AD 13-12-14-24W2 well (Figure 4). Presently, the configuration of this feature can only be speculated upon using information from a 30 year old composite seismic map (Sawatzky in Holter, 1969) and recently processed gravity data that identify it as about 5 km across (Miles *et al.*, 2000). The Deadwood isopach trends in southeastern Saskatchewan are strikingly similar to the orthogonal pattern of surface and subsurface lineaments described in the literature (Figures 2, 3 and 9). This similarity implies that the basement highs are genetically related to the lineaments, perhaps by a stress regime in the Precambrian basement that is periodically reactivated. The close proximity of the anomalously high Precambrian basement in the Amerada Crown S AD 13-12-14-24W2 well with a reported site of a magnitude 5 (Richter Scale) earthquake may be evidence of such reactivation in recent times. Earthquake activity in this region is thought to be related to movement along faults between blocks of rigid basement. Mollard (1987) shows that the distribution of seismicity has northwesterly, northeasterly and northerly trends.

Stratigraphy and Depositional History

In southeastern Saskatchewan, the basal unit of the Bighorn Group is termed the "Red River" and is formally subdivided into an upper formation, the Herald, and a lower, the Yeoman, (Kendall, 1976) (Figure 10). Where this subdivision cannot be recognized on geophysical logs, Red River Formation is used (Kreis and Haidl, 2000). In the U.S. portion of the Williston Basin (Figure 2), the term Red River Formation is used, and is further subdivided into drilling-based informal intervals called the "A", "B" and "C" in descending order (Longman and Haidl, 1996).

The monotonous succession of burrow-mottled and mainly lime mud-supported sediments in the Yeoman implies low-energy conditions through most of the time that they were being deposited, but, in places, thin storm sheets made up of skeletal grainstones and packstones punctuate the succession and are indicative of intermittent higher energy conditions. The presence of horizontal to oblique burrow mottles in the Yeoman Formation suggests the sediments were below fairweather wave base (Kendall, 1976).

The basal Lake Alma represents shallowing prior to restriction of the sea, leading to the accumulation of penesaline rocks of the "C" Laminated and the hypersaline Lake Alma Anhydrite. The normal-marine, shallow-water setting represented by the thin basal Lake Alma rocks presents the most varied facies relationships found in the Bighorn Group. The overlying Coronach replicates the Yeoman–Lake Alma succession except an equivalent to the basal Lake Alma interval is absent. The

top of the Coronach may represent an important hiatus. This interpretation is based on the presence of intraformational breccias in four cores. The Redvers is predominantly laminated to bedded and may represent a penesaline environment similar to that indicated by the laminated facies near the base of the Lake Alma.

Structural Controls on Facies Distribution

Kent (1987) described conditions in which sediment distribution in overlying strata might be controlled by regional and local structural features. On the basis of his observations, the shallow-water sediments of the basal Lake Alma are an obvious interval to study for anomalous facies developments as they would have more sensitively reflected bathymetric changes than the deeper water sediments of the Yeoman. Anomalous facies developments coincident with anomalous thinning or thickening of a stratigraphic interval provide evidence for syn-depositional structural control (either criterion alone is not firm evidence for such control).

Three of the maps presented here are significant to this study. The Deadwood isopach map (Figure 4) and the Precambrian structure map (Figure 6) demonstrate the existence of Precambrian basement paleotopographic highs in southeastern Saskatchewan. The Red River isopach map (Figure 5) shows thinning over some of these features, a commonly recorded characteristic elsewhere in the basin (Byrd, 1978; Martens, 1978; Mueller and Klipping, 1978; Sharp, 1978). This thinning can be attributed to syn-depositional upward movement of the reactivated basement highs. The basal Lake Alma in core from wells located over basement highs in the Chapleau Lake, Tyvan, Montmartre and Midale areas is made up of oolitic dolo-grainstones and dolo-packstones (Figure 11). Stromatoporoid-microbialitic banks occur over a high in the Weir Hill area, as do parts of tidal-flat complexes in the Ceylon area (Figures 1 and 11). In contrast, basal Lake Alma cores from wells that are close to, but not over basement highs, have ooids in dolo-wackestones and dolomicrites. From more distally located wells, they are generally skeletal wackestones and lime mudstones. Yeoman wackestones containing favositid and cateniporid corals and thick-shelled, robust brachiopods in core from Chapleau Lake, Tyvan and Montmartre may also subtly reflect shallower seafloor at these localities. The biota contrast with thinner valved brachiopods and an absence of colonial corals in Yeoman cores taken at some distance from the highs. A possible subaerial exposure surface is present at the top of the Coronach in Midale 12-2-7-11W2, also located over a basement high.

Economic Considerations

To date, all Red River hydrocarbon production in southeastern Saskatchewan appears to be underpinned by Precambrian basement with measurable positive paleotopographic relief. Producing wells which penetrate the basement invariably show some thinning or complete absence of the overlying Deadwood Formation. The assumption therefore appears reasonable that wells which do not penetrate the Precambrian, but show Red River

hydrocarbon entrapment, are likely to overlie a basement high. The apparent orthogonal arrangement of basement highs recognized from isopach mapping of the Deadwood and similar patterns from lineament mapping may prove useful as trend indicators for future plays of this type.

Generally, structural highs on the Precambrian surface (Figure 6) show up as structural highs on the top of the Red River (Figure 7) suggesting a genetic relationship. Also, hydrocarbon production is generally greater over the structurally highest Red River locations which tend to coincide with relatively higher paleotopographic relief on the basement. Bearing this in mind, the Amerada Crown S AD 13-12-14-24W2 well location, which shows the highest positive relief on the Precambrian basement yet recognized from mapping in southeastern Saskatchewan, is highly prospective (Figures 4, 6, and 7). The Yeoman portion of the Red River was not drillstem tested in this well, and evaluations of the SP, resistivity, gamma-ray and neutron logs taken in 1958 are inconclusive. Cores were not taken but cuttings show some zones of porosity and oil stains within the Stony Mountain Formation and the upper portion of the Yeoman Formation. Fluorescence micro-spectrometry studies suggest that the stains contain 30° to 35° API oil. Optical data from reflectance and fluorescence analysis of macerals in kukersitic source rock intervals associated with the stained cuttings show that the macerals are thermally immature to marginally mature. The oil found in this well has, therefore, probably migrated from a mature, downdip source (L.D. Stasiuk, pers. comm., 2000).

Conclusions

1) To date, all Red River hydrocarbon production in southeastern Saskatchewan appears to be underpinned by Precambrian basement with measurable positive paleotopographic relief.

2) The apparent orthogonal arrangement of basement highs recognized from isopach mapping of the Deadwood and similar patterns from lineament mapping may prove useful as trend indicators for future plays of this type.

3) In general, structural highs on the Precambrian surface (Figure 6) show up as structural highs on the top of the Red River (Figure 7) suggesting a genetic relationship.

4) Identification of concentrations of oolitic or stromatoporoid-microbialitic bank facies in basal Lake Alma wells that do not penetrate Precambrian basement might be indicative of an area close to or overlying a Precambrian basement high. A secondary indicator may be the presence of coarse skeletal remains of catenoporid or favositid corals, thick-shelled brachiopods and high-spired gastropods. Recognition of basement highs will help to focus exploration efforts.

5) Structural and stratigraphic mapping, along with seismic, gravity and fluorescence micro-spectrometry evidence suggests that the area in and around the Amerada Crown S AD 13-12-14-24W2 well is highly prospective for hydrocarbons.

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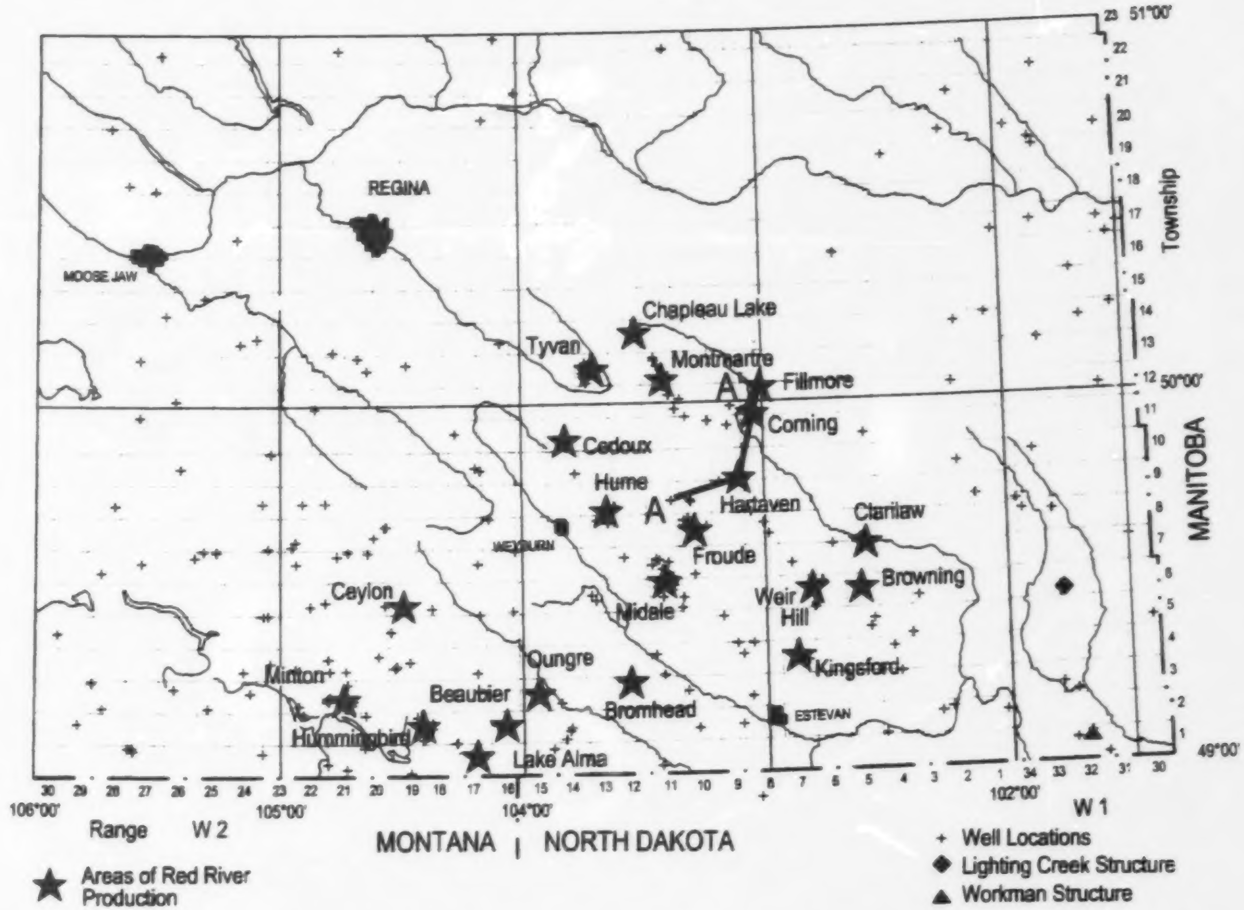

Figure 1 - Study area showing areas of Red River hydrocarbon production in southeastern Saskatchewan.

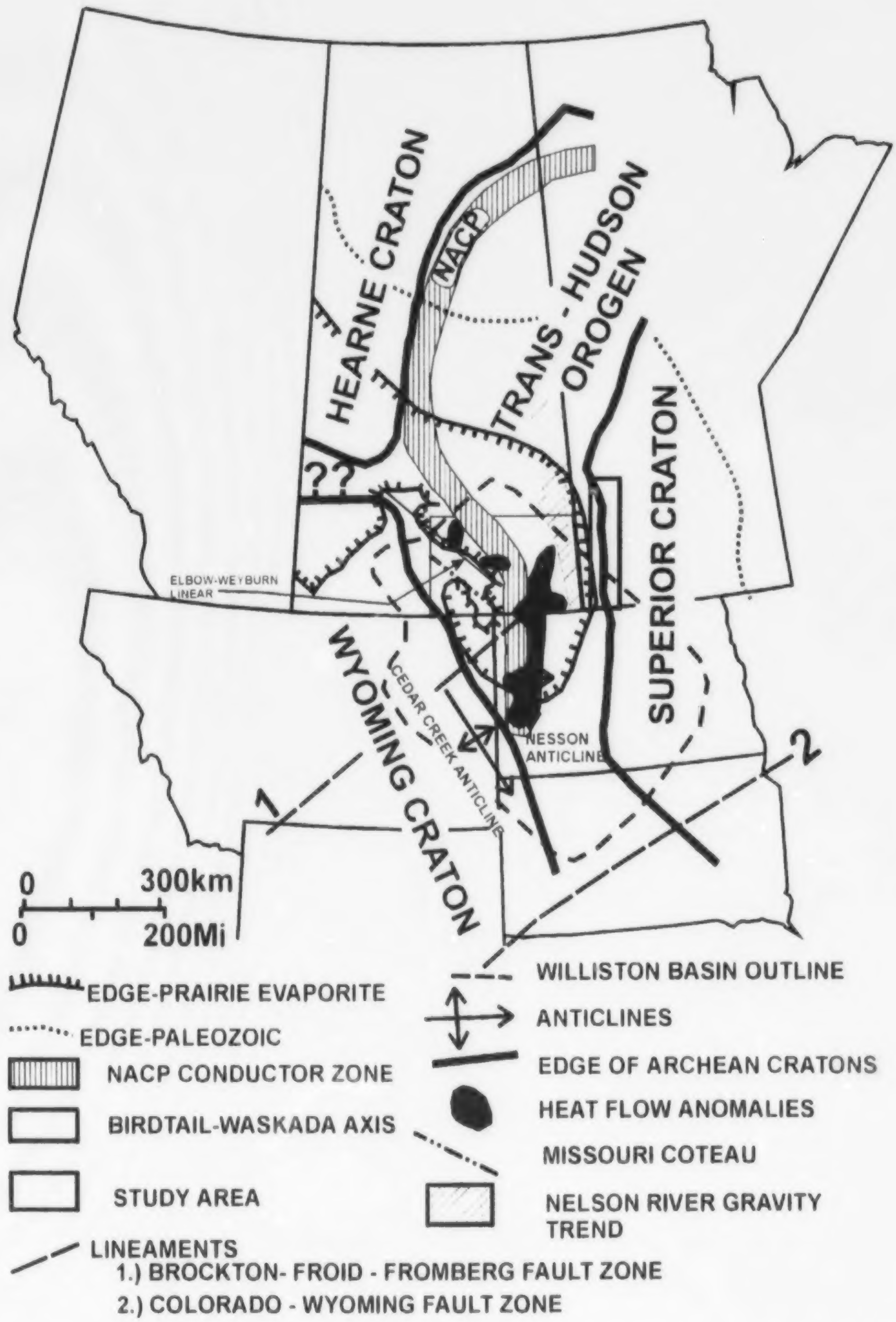

Figure 2 - Map showing major Precambrian basement features and subsurface and surface lineaments within and conterminous with the study area (modified from Kent, 1987; Majorowicz et al., 1988; and Baird et al ., 1995)

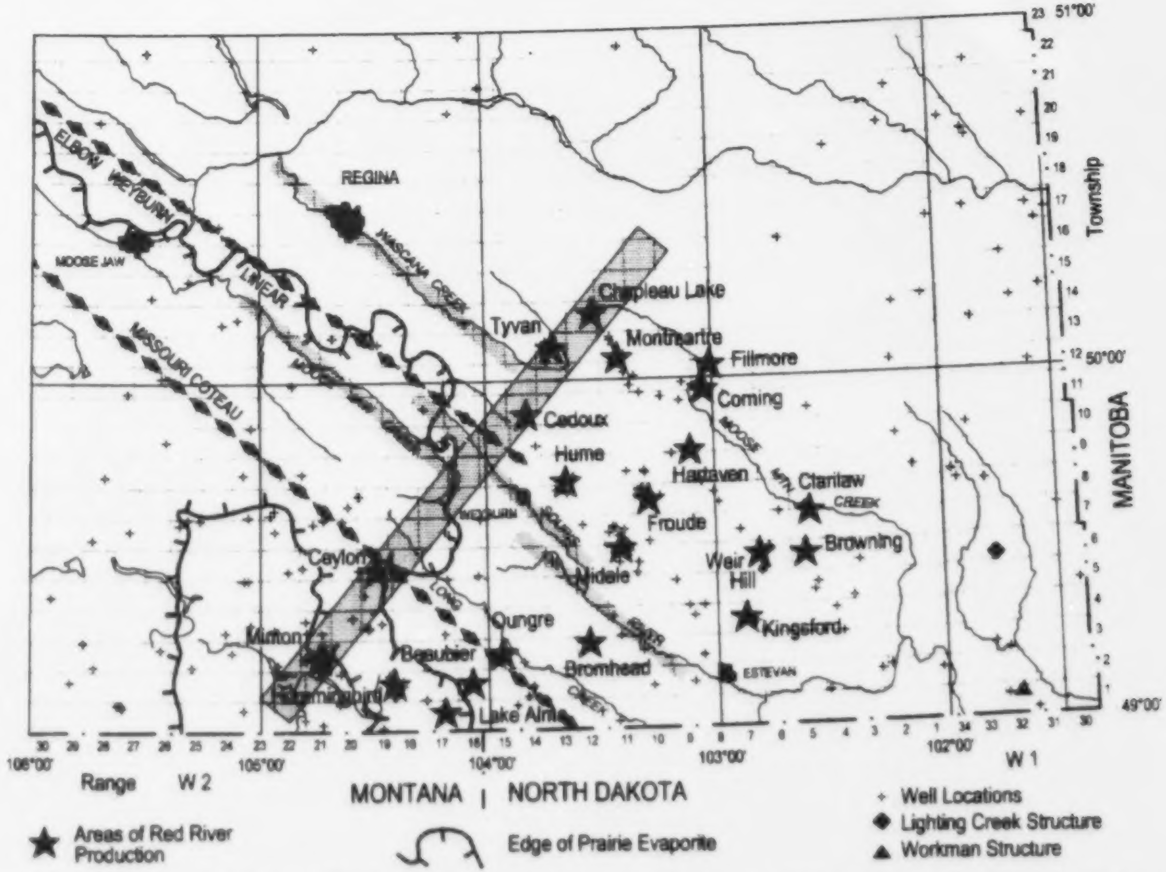

Figure 3 - Missouri Coteau, Elbow-Weyburn trend and water drainage show a northwest-southeast orientation. U-bends causing the Wascana Creek, Moose Jaw Creek and Souris River to reverse their flow directions are located in or near a northeast-trending area indicated by dark grey shading. Also, Moose Mountain and Long Creeks rise close to this area.

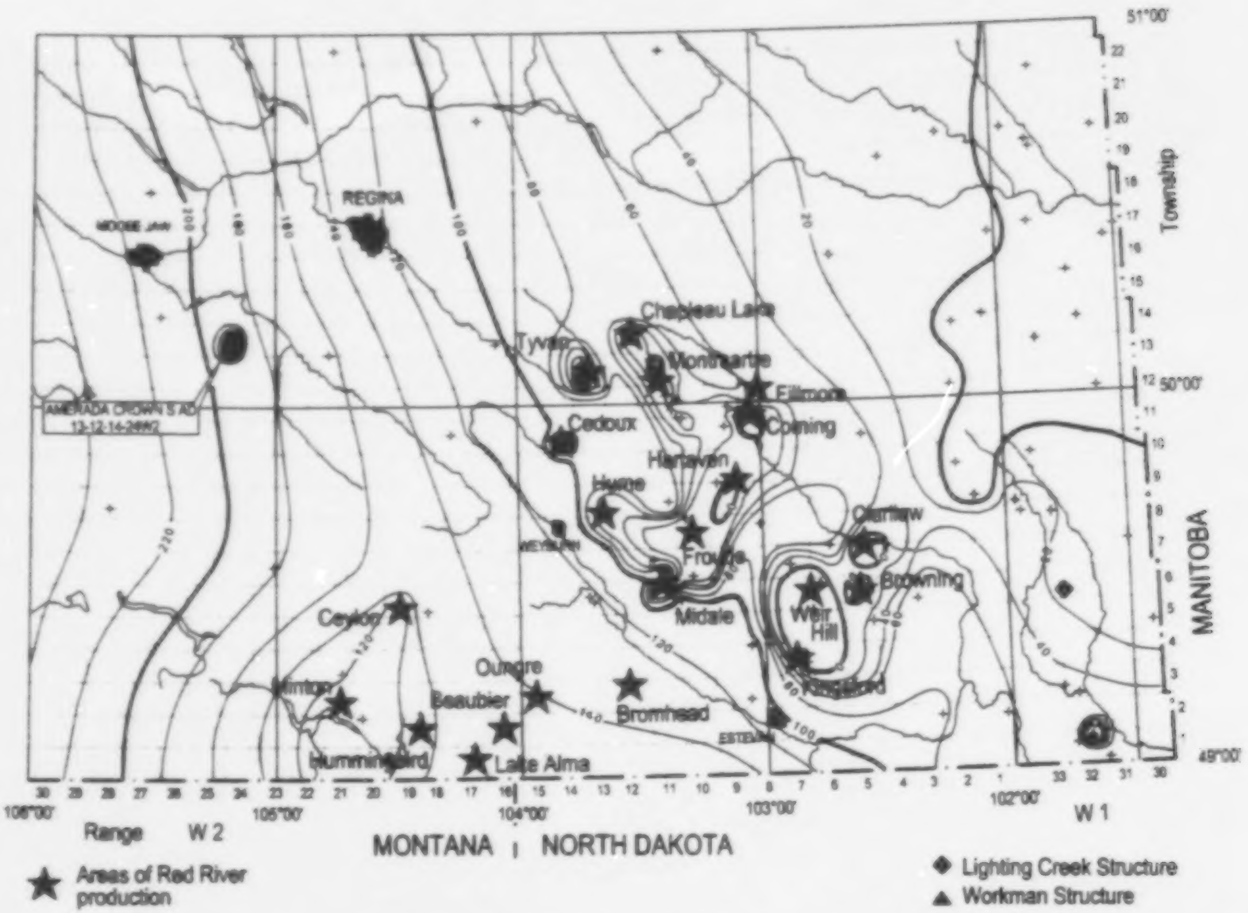

Figure 4 - Deadwood isopach map (from Kreis, 2000a). Contour interval is 20 m.

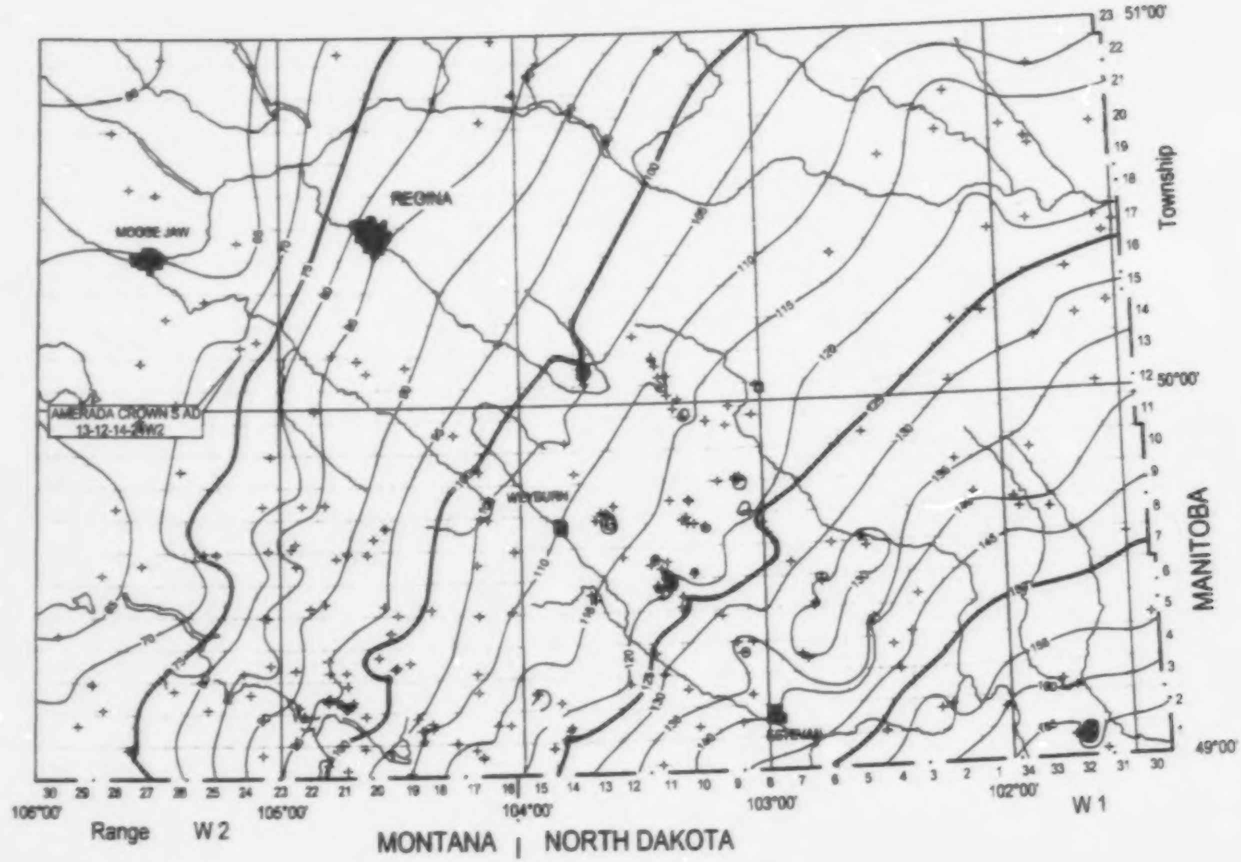

Figure 5 - Red River isopach map (from Kreis and Haidl, 2000). Contour interval is 5 m.

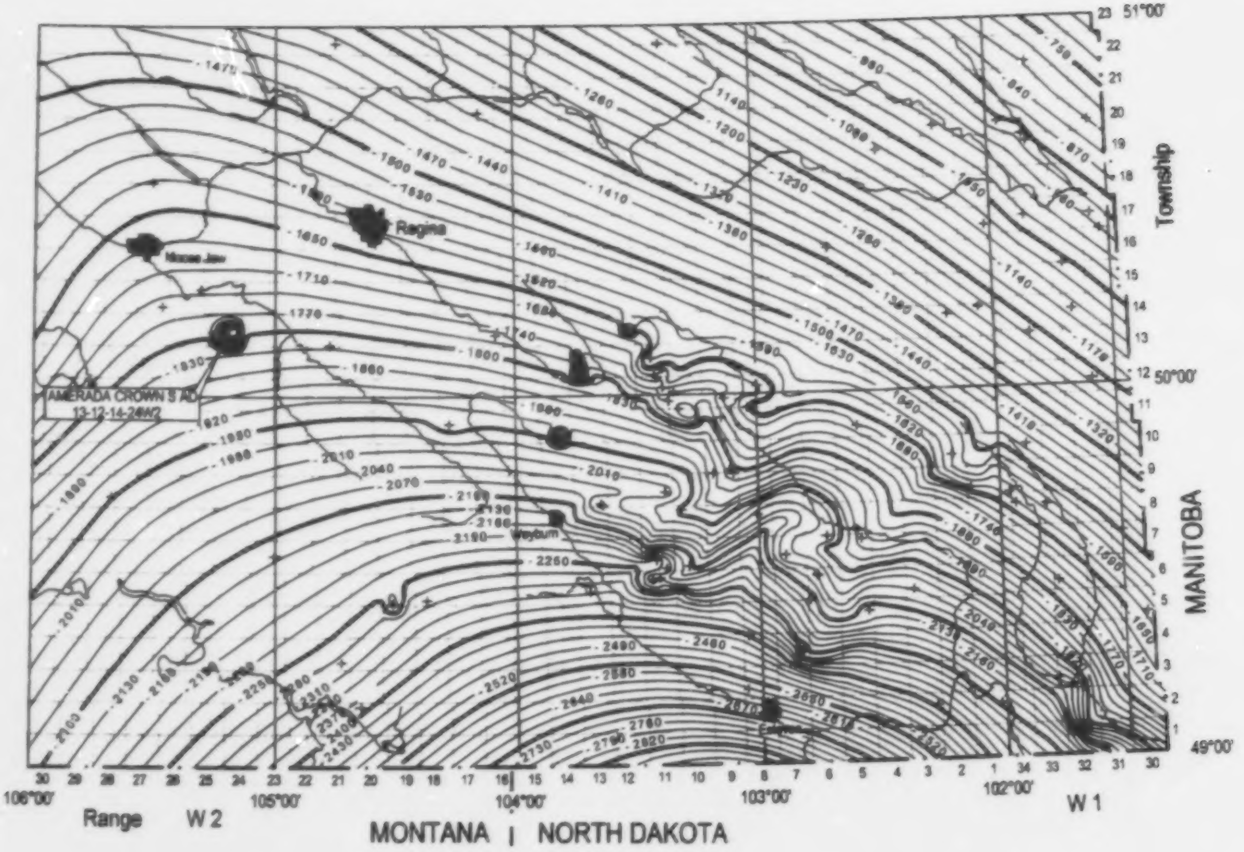

Figure 6 - Precambrian structure map (from Kreis et al., 2000). Contour interval is 30 m.

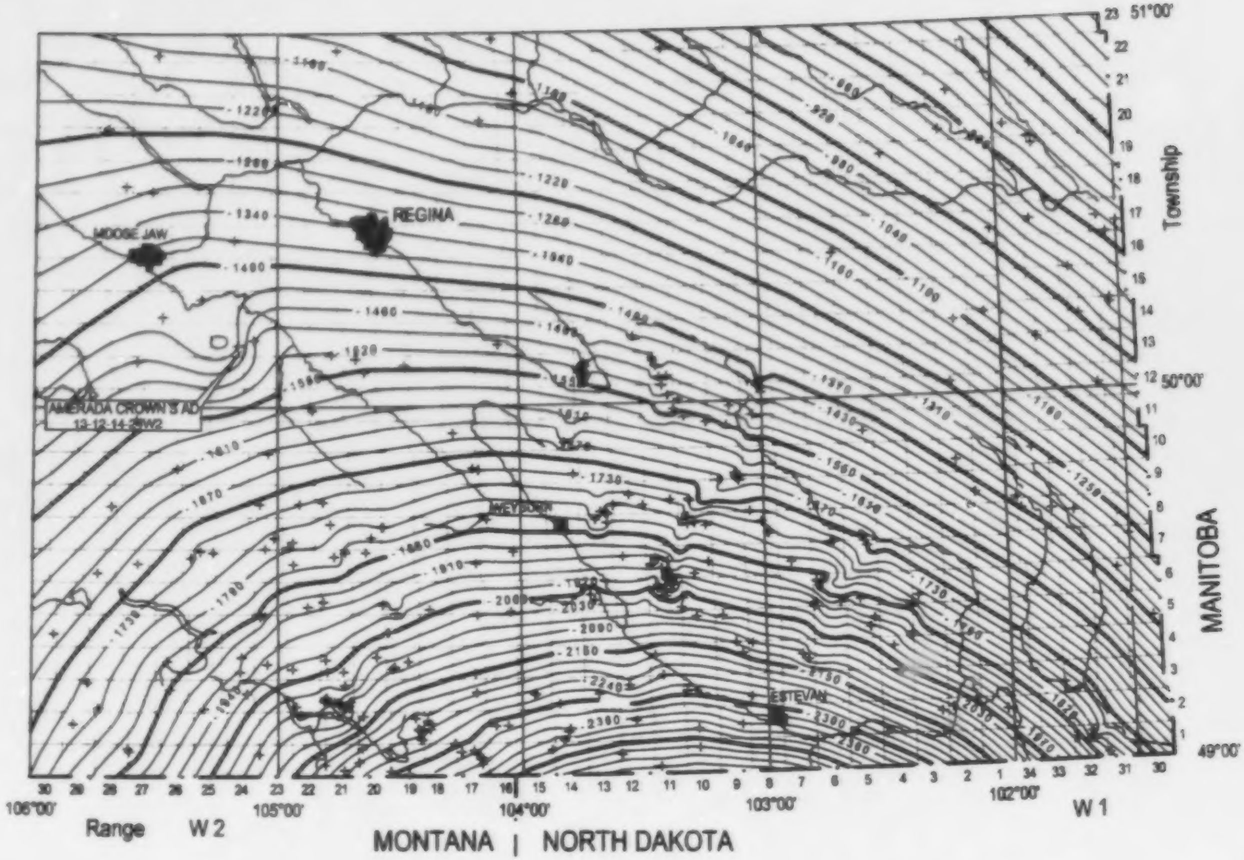

Figure 7 - Red River structure map (from Kreis and Haidl, 2000). Contour interval is 30 m.

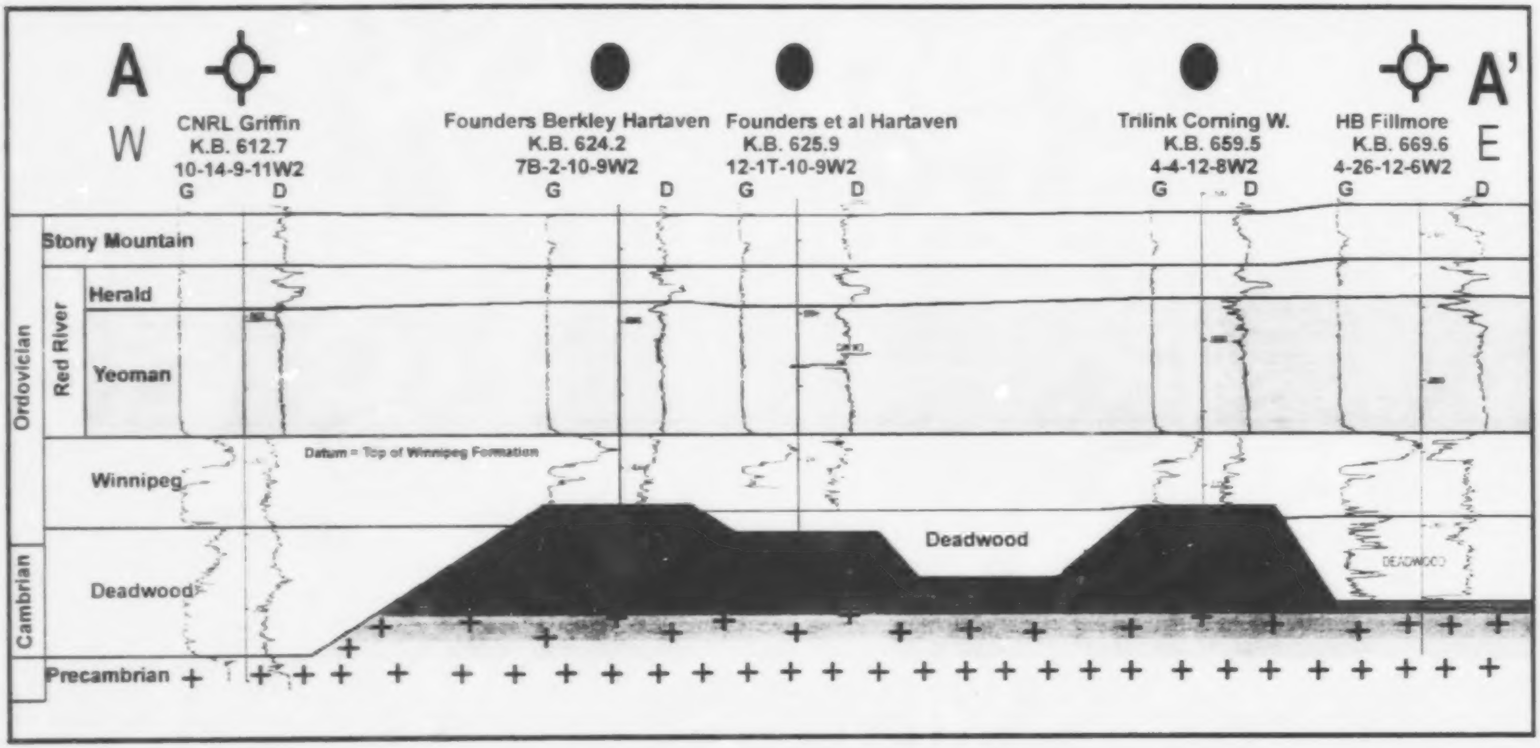

Figure 8 - Cross-section A-A' along axis of northeast-trending positive paleotopographic relief onPrecambrian surface. Note that the 10-14-9-11W2 well is slightly off trend (see figure 1) and shows no relief on the basement (modified from Haidl et al., In press)

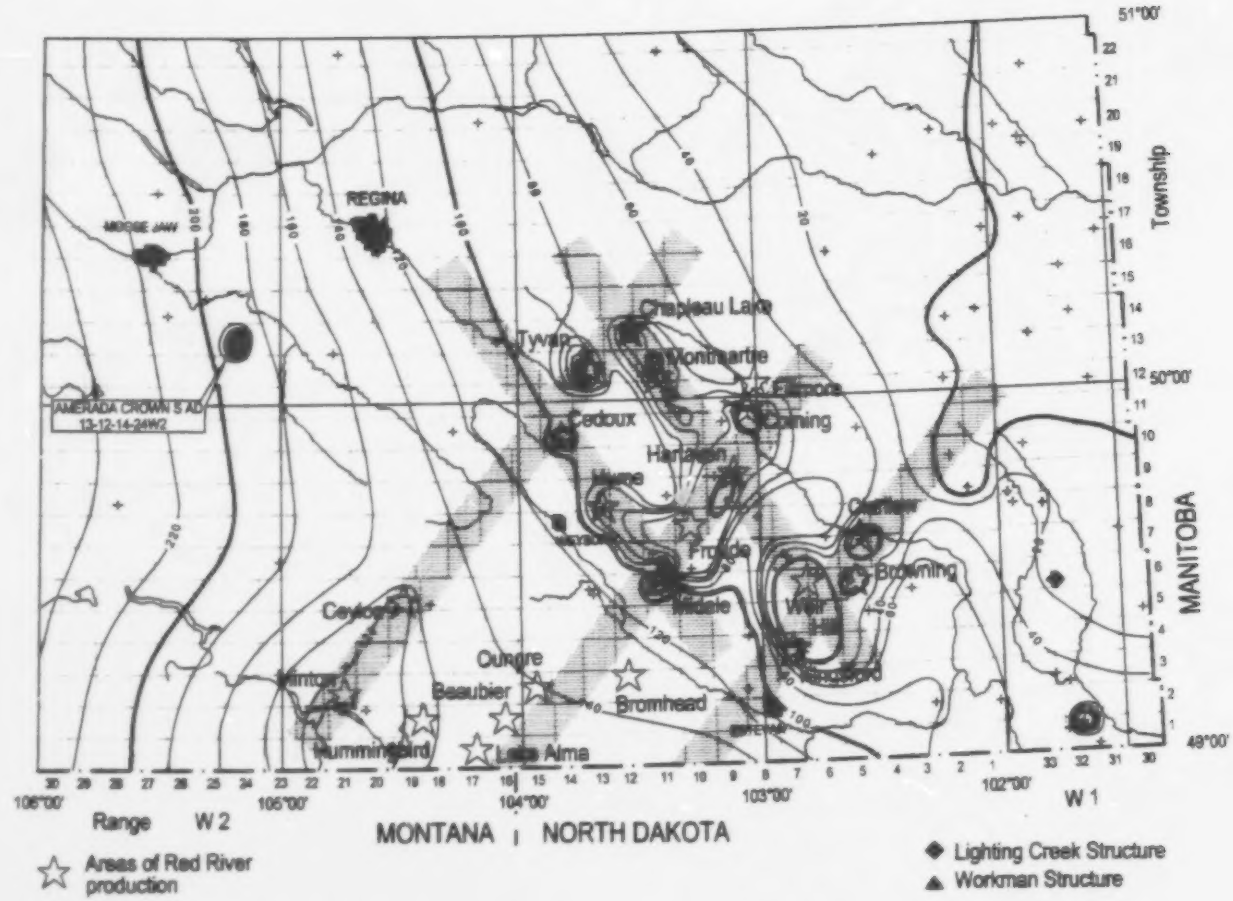

Figure 9 - Deadwood isopach map showing northeast and northwest-trending elongate areas of thinning over basement highs. Note that many of the Red River pools are situated within these areas. Contour interval is 20 m.

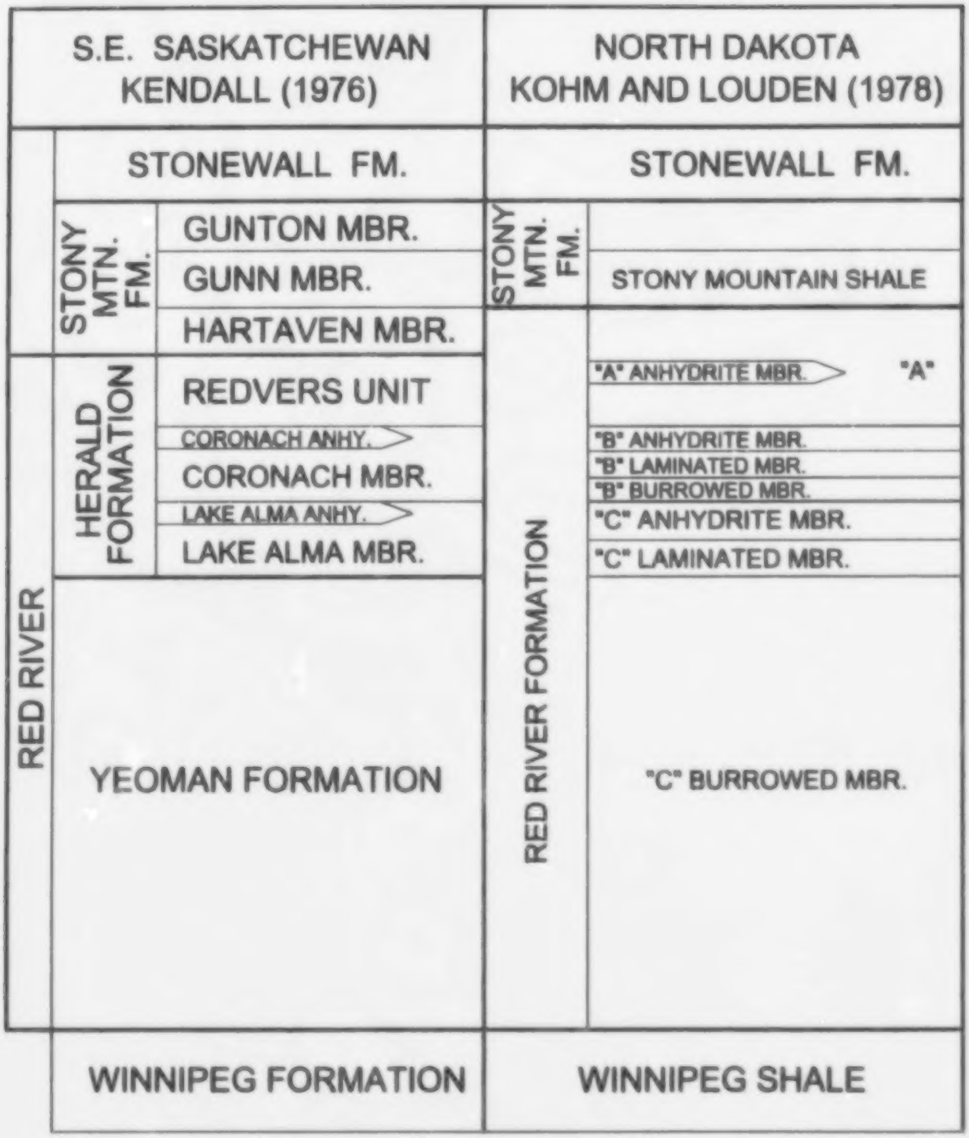

Figure 10 - Correlation chart showing stratigraphic nomenclature of Red River (Yeoman and Herald) and adjacent strata in Saskatchewan and North Dakota.

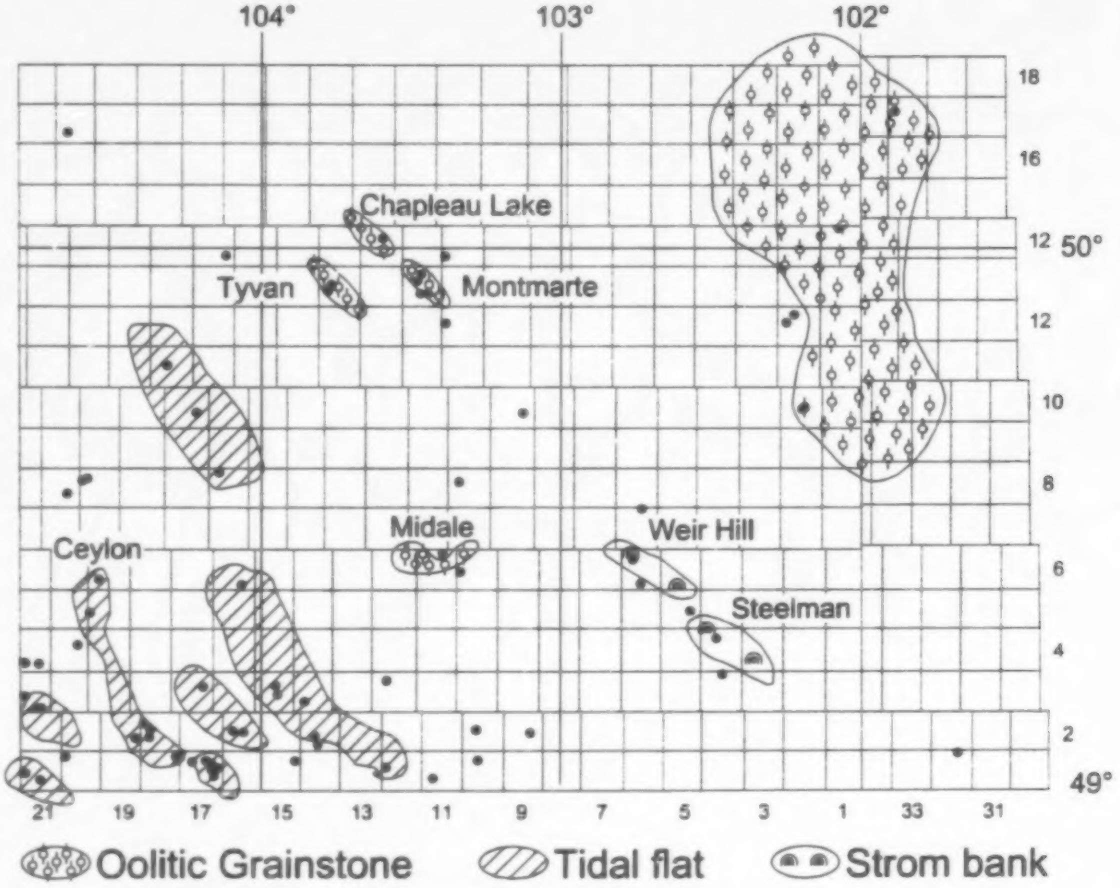

Figure 11 - Basal Lake Alma facies map

Five Theoretical Things Explorers Need to Know About Salt Dissolution and Collapse

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FIVE THEORETICAL THINGS EXPLORERS NEED TO KNOW ABOUT SALT DISSOLUTION AND COLLAPSE

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The post-depositional dissolution of subsurface evaporite deposits and the subsequent collapse of overlying strata into the resulting void are widespread phenomena occurring in numerous salt-bearing sedimentary basins. Geologists working the Williston Basin call these two separate but intricately related phenomena "salt collapse". This paper presents five theoretical considerations that will help a geologist in understanding salt collapse structures when encountered in the subsurface. These are:

1. Salt dissolution in space and time;
2. Prairie stratigraphy and mineralogy;
3. Geochemistry and rock mechanics;
4. Collapse structure architecture; and
5. Distribution of reservoirs within collapse structures.

Salt Dissolution in Space and Time

It is important to distinguish between the process of removing a volume of salt, potash, and carnallite from the Prairie and the subsequent collapse of the resulting cavern, both of which may be very separate and distinct events. The process of removing a volume of salt may occur episodically over a considerable time period, i.e. from shortly after salt deposition to the present day. Even within individual collapse structures, portions of the structure may have collapsed prior to other parts of the structure.

Periods of enhanced salt dissolution and removal are related to widespread unconformities and subaerial exposure, for it is during these times that a downdip water gradient force undersaturated waters into the subsurface and into contact with the salt. Cavern collapse is often related to marine transgressions, with cavern fill sediment ("microbasin fill") associated with marine flooding surfaces and sediments of the transgressive systems tract.

The Elk Point Group and Stratigraphy of the Evaporite Sequence

It is important to understand the stratigraphy of the Prairie Evaporite Formation, especially the distribution of the various potash members. These are, in descending order, the Patience Lake, Belle Plaine, "White Bear Marker Beds", and Esterhazy. The individual beds consist of layers of halite, sylvinite (a mixture of halite and sylvite), carnallite, and insoluble residues. Sylvite is potassium chloride and is the mineral mined for its fertilizer value, and carnallite is potassium – magnesium chloride.

Generally the four units can be readily identified, and can also be identified by means of clay seams. If a unit is missing, it is because the potash was dissolved away or was replaced by halite. If the potash was dissolved, the clay seams are usually also removed; however if the potash was replaced by halite, the marker seam was typically preserved.

Knowledge of the stratigraphy of these units greatly aids a geologist in interpreting the history of the Prairie because the presence or absence of the potash members reveals whether dissolution occurred from the top, bottom, or not at all.

The Role of Geochemistry and Rock Mechanics

Studies of fluid inclusions within samples of potash rock have yielded surprising results concerning the diagenetic history of the upper Prairie Evaporite. Determinations of burial depth and temperature based upon oxygen isotopes show that the potash ore is epigenetic, having formed at a much later date than the deposition of primary potassium chloride. It has been shown that this recrystallization occurred as late as the Cretaceous, thus suggesting that fluids were in contact with the potash beds much later than the Middle Devonian.

Rock mechanics is crucial in understanding how the process of cavern collapse occurs. Whether a rock breaks upon reaching a certain level of strain, or whether it deforms in a plastic manner, is a function of its rock mechanical properties, including matrix porosity. For example, low porosity limestones and dolomites are very strong (in terms of strength and stiffness) and comparable to granite, so they are capable of storing a significant amount of energy before failing. Argillaceous and organic material, and water-wet porosity significantly weaken carbonates, making them less able to support a load. Anhydrite beds are ductile and weak, so anhydrite beds will deform and flow rather than break. This means that the final geometry of a collapse cavern is dependent upon the mineralogy of the overlying rock mass.

Collapse Structure Architecture

The term "architecture" refers to the vertical and lateral extent of deformation caused by salt removal and collapse, including geometric factors such as height, width, and aspect ratios.

In the "typical" collapse structure two broad regions can be defined:

- The stope, consisting of cavern collapse rubble; and
- The surrounding zone of influence, characterized by a variety of rock phenomena.

The dominant effect that collapse has upon the rock section is firstly the modification of porosity and permeability and secondly, the substitution of "normal" sediments with a variety of anomalous rock types. Contrary to popular belief, not all collapse structures are porous chimneys; in fact, not all portions of the same structure are porous and permeable. A distinct lithofacies profile is typically present within a collapse structure, and is present both vertically within the structure and outward from the stope into the undeformed country rock. The progression is from chaotically bedded polymictic breccias to locally bedded oligomictic breccias to "crackle breccias" to fractured but otherwise undisturbed country rock. The thickness of individual lithofacies is a function of the rock mechanical properties of the rocks forming the pre-collapse cavern roof.

In addition to a unique sequence of breccias found within the collapse structure, anomalous sediments also occur within the basin formed at the paleosurface during the period immediately following cavern collapse. These sediments are named "microbasin fill" and typically consist of the same rock type as was deposited outside the collapse sink

Reservoirs Associated With Collapse Structures

Examination of cores from the vicinity of known collapse structures such as Kisbey and Walpole Saskatchewan show an alteration pattern which may be related not to a depositional process but rather to the cross-formational fluid flows created by the dissolution and collapse process. Since the actual collapse stope is typically poorly porous, fluids flow through the peripheral oligomictic breccias, crackle breccias, and collapse-related fractures. This "Walpole" type alteration typically results in recrystallization of the rock and distortion to near-obliteration of the fabric. Often significant porosity and permeability enhancement can occur, for instance in several wells in the Walpole area, where some individual beds have permeability in excess of 1 darcy.

It is possible to characterize the types of reservoirs that have been formed within areas of partial to complete salt dissolution and collapse. The actual collapse stope is poorly porous and impermeable since it consists of silty, shaly polymictic breccia. The portion of the structure composed of oligomictic breccia is commonly porous and permeable, since it consists of loosely packed clasts. The best porosity is present within the crackle breccia, and although this rock type may not form a large portion of structure its flow potential is great since the fractures form an interconnecting mosaic. Fractured country rock present at the edges of the structure does not have significant porosity but does have tremendous permeability, thus providing the "pipelines" capable of significant water transmission through and surrounding the typical collapse structure.

The key in properly targeting a well to test for oil entrapment associated with salt collapse structures is understanding the architecture of the target structure, understanding its timing, and having a good grasp of its geophysical expression. In order to do this it is critical to precisely calibrate seismic response to rock type, ideally by means of core-based rock mechanical investigations. This allows the creation of an accurate rock and reservoir model.

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Relationships of Prairie Salt Dissolution and Collapse to Development of Oil Pools in the Williston Basin

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Williston Basin explorers are aware of the effects of Prairie Fm. (Middle Devonian) salt dissolution upon the outcome of exploration programs, with diverse structural and stratigraphic effects on overlying reservoirs, as well as effects of salt dissolution upon the seismic interpretation of deeper objectives. Although the effects of Prairie salt dissolution are identifiable by experienced explorers, often the underlying causes of salt dissolution in both time and space are either poorly understood, or not considered important. Reservoir enhancement within the halo of salt dissolution and brine migration is not simply a coincidence, rather a consequence of complex diagenesis related to large volumes of brines rising through overlying strata, particularly carbonate rocks. Rarely, potential reservoirs are destroyed by Prairie salt dissolution, apart from partial to complete salt re-precipitation in shallower reservoirs. Dissolution of vast thicknesses of Prairie salts basinwide at various periods of geological time in the basin history also contributes to widespread distribution of saline formation waters, particularly in Paleozoic strata. Based in part upon Prairie salt dissolution patterns, there is much evidence to suggest that present basinal hydrodynamic flow patterns are Tertiary in age, and do not represent flow patterns that existed earlier in basin history.

Prairie salt dissolution styles

This discussion draws upon a much more exhaustive reference on the subject of Prairie salt dissolution offered by the two authors as an industry short course(Halabura and Potter, 1999). In the space and time available, underlying mechanisms of salt dissolution, distribution of salt collapses basinwide and specific pool examples cannot be discussed in any detail. From the background on Prairie salt dissolution and effects upon oil and gas entrapment presented in the expanded short course reference, possibly the most important aspects that could be relayed to exploration and development geologists and geophysicists are diagnostic criteria used to identify and evaluate a salt dissolution anomaly, and possibly define an exploration prospect.

Obvious single stage salt collapse features of varying dimensions seen along seismic lines, or in detailed stratigraphic mapping, are rarely sites of oil entrapment, with the possible exception of thick sands deposited within the limits of a collapse. Instead, Williston Basin oil pools related to Prairie salt dissolution are discovered in one of the following more complicated configurations:

i. **Multiple stage collapses**: Within broad areas of salt dissolution and collapse covering many sections to townships, several periods of dissolution in geological time create typical *Hummingbird type* multi-stage structural closures (Smith and Pullen, 1967), with several potential pay zones. Areal extent of the multiple-stage salt disslution features is typically less than one square mile in size as seen in the Hummingbird and Lake Alma Ratcliffe and Nisku/Birdbear pools in southern Saskatchewan, and the Tule Creek, Volt and Palomino Nisku pools along the Wolf Creek Nose in Roosevelt County, Montana.

ii. **Structural rollovers into no-salt areas**: Oil pools are found trapped upon thick Prairie salt and immediately down dip of broad salt collapses in a simple structural rollover configuration. Ascending saline brines can potentially alter and leach overlying strata, particularly carbonate rocks, to create isolated prolific hydrocarbon reservoirs. Pool examples include the Target and Redbank Ratcliffe and Midale Beds pools , Roosevelt County, Montana and the Flat lake Ratcliffe pool of Saskatchewan and Sheridan County, Montana.

iii. **Paleoerosional traps beneath unconformities**: Beneath the Mesozoic Unconformity, potential reservoirs are preserved from erosion within the limits of a Prairie salt dissolution and collapse low or trough. Across southeastern Saskatchewan, and beyond into North Dakota, Mission Canyon, Midale, and Ratcliffe reservoirs are preserved in irregularly shaped dissolution lows beneath the Mesozoic Unconformity in numerous simple to complex configurations. Most of these examples are found in areas of prolific Winnipegosis reef development beneath thick Prairie salt. Typically, the carbonate reservoirs are enhanced within the vicinity of each dissolution feature.

iv. **Structural drape across salt 'pillows' or outliers**: Isolated 'pillows' of Prairie salt within broad *no-salt* areas create structural closure of overlying Devonian and

Mississippian reservoirs. Examples include the Innes Mission Canyon pool , Saskatchewan and the Virden/Scallion/ Roselea Lodgepole Fm. pools of southwestern Manitoba.

v. **Microbasin/collapse low sediment infill**: During periods of collapse into an underlying salt dissolution void, carbonate and sandstone reservoirs are deposited in isolated *microbasins* . The best examples are recognized in the Cretaceous aged Mannville heavy oil pools of western Saskatchewan. In eastern Saskatchewan, *microbasin fills* are productive in the Gainsborough East, Rocanville and Wapella oil pools. There remains some controvery as to whether the Dickinson Lodgepole 'mounds' are in some way related to *microbasin fill*.

vi. **Complex diagenetic traps**: Stratigraphic traps in carbonate rocks are created within , or just peripheral to, a Prairie salt dissolution collapse. At the Dolphin pool in Divide County, North Dakota, saline brines rising through Dawson Bay Fm. shoal rocks from an underlying Prairie salt dissolution collapse created leached to cavernous porosity across a prominent structural nose. Oil is trapped within the limits of the leached Dawson Bay reservoir, surrounded by non-reservoir facies . The leached /cavernous porosity has been partially infilled with clear halite towards the margin of the dissolution feature, presumably representing a period of salt saturation and no further fresh water inflow.

Processes leading to Prairie salt dissolution

Observations of structural and stratigraphic complications that develop within the limits of a Prairie salt dissolution feature continues to offer explorers countless exploration opportunities in both mature and unexplored portions of the Williston Basin. To simplify the broad topic of Prairie salt dissolution and the direct effects upon oil and gas entrapment, a list of relevant criteria is offered for explorers. In any successful exploration program, both the geologist and geophysicist must have an understanding of the processes and causes of salt dissolution and collapse in order to recognize prospect opportunities and avoid drilling risky exploration tests.

Once into a development scenarios, the principles of salt dissolution and collapse continue to carry as much , if not more, value in understanding structural and stratigraphic complications.

Before describing specific criteria used to identify salt dissolution features and prospects, we need to briefly answer some relevant questions regarding processes leading to Prairie salt dissolution:

What is required to initiate salt dissolution at a specific location in the basin?

Fresh cold water with continuous meteoric recharge from shallower margins of the basin, flow through porous Devonian strata and continuous fault trends into deeper portions of the Basin. Under significant hydrodynamic head, the fresh water flows upwards to lower pressure regimes, through thick Prairie salt beds, presumably dissolving the most soluble sylvanite and carnalite minerals first, followed by halite dissolution. . Thus not only fresh water, but also strong fluid dynamics are required to transport fresh water basinwards.

Where does the heavy salt brine travel from areas of major Prairie salt dissolution voids or caverns?

Under hydrodynamic pressure, the heavier brines will ascend to shallower strata above the Prairie salt to a point where fluid density is too great and/or halite precipitation occurs at lower temperatures. Within the no-salt Hummmingbird Trough in southern Saskatchewan, fluid salinities of greater than 300,000 ppm in strata beneath the Winnipegosis Fm. suggests some gravity-driven downwards flow of Prairie salt brines.

Why does salt dissolution occur at specific and very predictable periods of geological time, separated by long periods of no dissolution?

The simple answer is that recharge of fresh water into the deeper basin strata occurs during periods of relative sea level fall or uplift along the basin margin with exposure and erosion of Devonian strata along the basin margin. Meteoric waters enter porous outcropping Devonian strata and flow basinwards to thick preserved salt beds nearest the basin center.

Do basement faults play a significant role in Prairie salt dissolution?

Faults act as fluid conduits to transport fresh waters basinwards, as well as provide vertical conduits within the limits of a salt dissolution cavern to transport saline brines to shallower elevations. Faults that extend from the basin margins inot the deeper basin, such as the Brockton –Froid Lineament of Montana and North Dakota, served to transport fresh waters basinwards, and create the Anvil Trough of total salt dissolution in Roosevelt County, Montana. In contrast, the Nesson Anticline is essentially confined to the deep basin center and thus is not a common site of Prairie salt dissolution.

Key exploration guidelines for recognizing effects of Prairie salt dissolution

Essential criteria that explorers should consider when exploring in areas of potential Prairie salt dissolution in the Williston Basin are summarized as follows:

1. Basinal setting of project area relative to present or original Prairie salt thickness

A clear understanding of the Winnipegosis depositional basin configuration and lithologies and anticipated original Prairie salt thickness overlying the Winnipegosis Fm. in any project area is the most important criteria. The thickest Prairie salts occur in central Saskatchewan and in Burke County, North Dakota where up to 200m of original salt was deposited within a pinnacle reef basin. Across the Winnipoegosis shelf towards the basin margins, the salt thins dramatically to zero. In most cases, thicknesses of 20m and less have largely been altered by regional salt dissolution.

Once an original salt thickness has been established in a specific project area, a *salt budget* can be developed, reconstructing periods and quantities of salt dissolution. In other words, where 20m of original salt once existed, up to 20m of structural closure could be anticipated in a structural prospect.

2. Confining strata, porosity trends and regional structures

As discussed, fresh waters enter the thick salt beds and initiate dissolution through porous salt confining strata including: Winnipegosis reefs in the basin center; coral-stromatoporoid banks along the Winnipegosis shelf margin; Dawson Bay carbonate shoal trends; and continuous basement fault trends. The best example of the relationship of confining strata to dissolution trends is seen where the limits of Hummingbird Trough of southern Saskatchewan coincides very closely with a broad porous Winnipegosis coral-stromatoporoid bank trend along the western Winnipegosis shelf margin. Towards the Winnipegosis basin center, countless sites of Prairie salt dissolution coincide with underlying porous Winnipegosis reefs. In part, the Winnipegosis dolomite porosity in reefs and banks may be related to upwards migrating fresh waters during periods of salt dissolution. The Brockton-Froid Lineament is an excellent example of fresh water flow along basement faults from the basin margin into deeper portions of the

basin. The Anvil Trough of Roosevelt County , Montana of complete salt dissolution was created in Cretaceous time along this structural trend by fresh water dissolution .

3. Timing of Prairie salt dissolution and collapse

Prairie salt dissolution was 'triggered' at brief intervals in geological time during either regressive events with a relative sea level fall, or during periods of tectonic uplift surrounding the basin. At this time, fresh meteoric waters entered exposed porous confining strata along the basin margin and flowed to deeper points in the basin. Thus, explorers see evidence of Prairie salt dissolution and collapse during and following basinwide periods of uplift and erosion, such as at the Mesozoic Unconformity. Dissolution and collapse during and following basinwide exposure and erosion at the Mesozoic Unconformity accounts for numerous oil pools trapped below the unconformity in the Ratcliffe, Midale and Mission Canyon Fms., and above in the Watrous Red Beds or Spearfish sands(South Westhope/Newburg pools, North Dakota;Manor pool, Saskatchewan). Another common event of Prairie salt dissolution and collapse coincides with erosion at the Three Forks Fm. top. Significantly thickened Lower Bakken shale is found within many collapse features, with lesser thickening in the overlying Middle Bakken siltstone, and rarely any thickening in the Upper Bakken shale.

Depending upon the timing of Prairie salt dissolution at any given site, single stage or multiple stage anomalies may be created with entirely different hydrocarbon trapping characteristics. As discussed, single stage anomalies typically trap hydrocarbons along structural rollover/ faulted margins (ie. Redbank/Target pools, Roosevelt County, Montana), within porous microbasin fill such as the Middle Bakken sand Rocanville pool in eastern Saskatchewan, in faulted reservoirs within the perimeter of a salt collapse (Kirkella Lodgepole pool, Manitoba), or upon a thick preserved salt pillow, as seen at Innes pool, Saskatchewan. More complex multiple stage salt dissolution anomalies, such as the Hummingbird pool in southern Saskatchewan create significant structural closures , often with carbonate reservoir enhancement.

4. Microbasin Fill

When a Prairie salt dissolution void or cavern collapses, a depositional low or *microbasin* forms above where porous carbonates or quartz sands may be locally deposited. Porous *microbasin fill* may create significant oil pools within single and multiple stage dissolution anomalies. Collapses that occurred during marine deposition, as seen in the Upper Devonian Souris River and Duperow Fms., are typically infilled with laminated lime mudstone and anhydrite microbasin fill. The thickened mudstones and anhydrite may form the thick compensated interval that later creates structural closure in multiple stage salt anomalies.

The term , *microbasin fill* is meant to be generic, with no specific lithological definition or geological age. In most cases. stratigraphic thickening will be recognized immediately above an area of salt dissolution in either well control or seismic data, provided that there is no subsequent erosion of the thickened interval. Total thickening of microbasin fill should add up to the initial pre-dissolution salt thickness.

5. Diagenesis of carbonate rocks: Walpole facies development

Salt saturated brines flowing upwards from a site of Prairie salt dissolution are capable creating significant limestone reservoirs through leaching , brecciation and possibly recrystallization of dolomite reservoirs. The term 'Walpole facies' has been used by Halabura and Potter,1999 to define a diagenetic limestone reservoir in the Nisku/Birdbear Fm. in the Walpole pool area of eastern Saskatchewan. Leaching of skeletal grains and intergranular matrix in limestones, often with large open dissolution vugs, is seen in Nisku/Birdbear cores immediately within the halo of Prairie salt dissolution at the Walpole pool. On well logs, overall porosity is typically much higher and thicker than in surrounding wells resting upon thick salt in areas of 'Walpole facies' development . Argillaceous gamma ray markers are usually preserved within this much more porous reservoir, in spite of extensive leaching. The term *Walpole facies* is used here to describe Nisku/Birdbear reservoir characteristics. However, similar characteristics are seen in Mission Canyon reservoirs in close proximity to salt dissolution anomalies.

Aeromagnetic anomalies have been recognized in strata immediately above a Prairie salt dissolution low, presumably due to re-precipitation of iron oxide and sulphide minerals from

saturated brines at cooler temperatures. Coincidentally, porous Nisku/Birdbear limestone reservoirs are found within this aeromagnetic halo.

Exploration opportunities related to Prairie salt dissolution and collapse

The effects of Prairie salt dissolution and collapse have a significant impact upon hydrocarbon trapping in the Williston Basin in a wide variety of configurations. With a better understanding of the processes that initiate Prairie salt dissolution, and recognition of pertinent criteria of the effects of salt dissolution, geologists and geophysicists will find numerous exploration opportunities in the Williston Basin in both mature and unexplored areas. The present day Prairie dissolution edge that surrounds the basin, and the vast no-salt area that lies beyond, offers significant potential for new reserves discoveries in single and multiple stage anomalies at relatively shallow depths. Deeper within the basin, dissolution along fault or porosity trends offers potential for a variety of salt dissolution related exploration prospects, often beneath existing shallower production. Along the northern basin limits in Saskatchewan where the Prairie salt is up to 200m in thickness, widespread complex dissolution patterns, structural anomalies, and salt pillows or outliers offer excellent exploration opportunities for both oil and gas discoveries.

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Oil Charge to the Shaunavon Trend in Southwest Saskatchewan

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OIL CHARGE TO THE SHAUNAVON TREND IN SOUTHWEST SASKATCHEWAN

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I. INTRODUCTION

The Shaunavon Trend is a chain of oil fields in middle Jurassic shoreline sandstones on the eastern flank of the Sweetgrass Arch in southwest Saskatchewan. The Shaunavon Trend oil fields are located more than 200 km away from the closest thermally mature source rocks, which are:

1. The Mississippian Lodgepole Formation in the Williston Basin of east-central Montana
2. The Lodgepole and Exshaw Formations in the Rocky Mountain Foothills of north central Montana.

In an attempt to understand where the oil charge to the Shaunavon Trend originated, Rakhit Petroleum Consulting Ltd. conducted Dynamic Migration Modeling over a regional area that includes both of these oil kitchens (Figure 1). A major assumption of the study is that the upper Mississippian Mission Canyon Formation was the carrier bed.

Our results indicate that under present day conditions (structural configuration and hydrodynamics), the Shaunavon Trend would receive no charge from the Foothills oil kitchen and only minor charge from the Williston Basin.

Paleo oil migration modeling was then conducted for a Paleocene migration event (Late Tertiary time: 66 – 58 Ma). This was a time of peak Laramide activity, with major oil expulsion from source rocks in the Foothills region and a stronger hydrodynamic drive than at present. Results indicate that during this event, oil sourced in the Foothills was driven over the Sweetgrass Arch then migrated northeast into the Shaunavon area.

By understanding how the Shaunavon Trend was charged, exploration can be focussed along the migration fairway where additional oil traps may occur.

II. OIL MIGRATION MODELING

Dynamic oil migration modelling is a proprietary tool developed by Rakhit Petroleum that determines the forces driving oil migration in the subsurface. The major driving forces are the oil buoyancy, which drives oil updip, and the hydrodynamic force, which drives oil in the direction of water flow. The hydrodynamic force can assist the buoyancy force (when water flow is updip), hinder the buoyancy force (downdip water flow) or alter the direction of buoyancy driven migration (i.e. water flow along strike).

Dynamic oil migration modeling determines the total driving force acting on oil, resulting from oil buoyancy and hydrodynamics. A series of maps are made each of which is then sampled to provide the data needed. The oil density and a structure contour map of the carrier bed provide the information needed to determine the buoyancy force. Hydraulic head and water salinity maps of the carrier bed provide the information needed to determine the hydrodynamic driving force. At each sample point, these two force vectors are added together and the dynamic oil migration force is represented by the resultant vectors (arrows) which are posted on the structure map (Figures 1 and 2). Migration routes can then be traced out by following the vectors from source regions. Along migration routes oil may be trapped under suitable conditions.

III. OIL SOURCE ROCKS

Biomarker evidence indicates that the medium gravity crude oils in the Shaunavon Trend oil fields such as Dollard, Instow and Rapdan have a Late Devonian or Mississippian source (Osadetz et al. 1994). Mature source rocks of this age only occur in two regions close enough to have charged the Shaunavon Trend oils, the Williston Basin and the Foothills region. The Williston Basin has thermally mature source rocks in the Bakken and the Lodgepole, with the Lodgepole being the source for the major oil fields along the Mississippian subcrop in southeast Saskatchewan and western Manitoba.

In the foothills of southwestern Alberta and north central Montana, mature Bakken/Exshaw source rocks have sourced many oil pools along the Sweetgrass Arch

in Montana (Dolson et al. 1993) and Mississippian and Lower Cretaceous pools in southern Alberta (Riediger et al. 1999; Allan and Creany, 1991). Additional source rocks likely occur in the Montana trough that runs through Lewis and Clarke and Cascade counties. The depositional environment in the trough may have been similar to that in the Williston Basin where the Lodgepole source rocks were deposited.

IV. OIL MIGRATION MODELING FOR THE PRESENT DAY

An initial attempt was undertaken to account for the location of the Shaunavon oils using present day oil migration modelling for the Mission Canyon Formation. By using present day structure, water salinity, hydraulic head and an oil gravity of 35 API, a model was generated. The results indicate that present day conditions cannot account for the Shaunavon accumulations migrating from mature source rocks in the Williston Basin or the Foothills to the West (Figure 1).

Potential migration from the west to the east is hindered by the presence of Eocene intrusions such as the Bearpaw Mountains in Montana. These highlands act as major recharge regions, influencing the hydrodynamics throughout Montana and the Williston Basin (Downey 1987). The recharging water in combination with the week west to east hydrodynamic drive over the Sweetgrass Arch prevents oil from migrating over the Arch towards the Shaunavon region (Figure 1).

The western recharge zones also prevent migration from the Williston Basin to the Shaunavon region. The strong recharge drives oil northeastward out of the mature Lodgepole source rocks in the Williston Basin towards southern Saskatchewan and Manitoba (Rakhit Petroleum Consulting Ltd., 1999). It was this driving force that has migrated the substantial oil reserves in Saskatchewan and Manitoba from the deeper mature regions of the Williston Basin in Montana and North Dakota (Rakhit Petroleum Consulting Ltd., 1999).

A single oil migration line does extend from a small region of mature Lodgepole source rock in the western Williston Basin to the Shaunavon area, but volume analysis indicates that this could not account for all of the Shaunavon Trend oils.

V. PALEO OIL MIGRATION DURING THE PALEOCENE (Early Tertiary)

Oil migration to the Shaunavon region likely occurred during the Paleocene. At this time, source rocks in the foothills region were at maximum burial depth and likely actively generating hydrocarbons. High pressures in the foothills oil kitchen due to a combination of compaction and hydrocarbon generation would have led to expulsion of the oils with strong migration forces directed towards the east.

Oil migration in the Paleocene throughout the study area differed significantly from the present day pattern because it pre-dated the Eocene igneous intrusions in central Montana. Present day recharge from the highlands of Eocene intrusives dominates the Williston Basin hydrogeology flow regime. During the Paleocene, before the highlands existed, water flow would have been driven in a simpler west to east direction from the deformation front in the Foothills towards the northeast. There is evidence for high hydraulic gradients from west to east related to the Laramide Orogeny during the late Cretaceous/Early Tertiary (Symons, et al. 1996; Qing and Mountjoy, 1994 and Machell, et al. 1995). This high gradient likely resulted from tectonic squeezing and compactional loading of sediments due to the Orogeny, increased pressures in the deeper basin due to hydrocarbon generation and possibly increased recharge from the elevated foothills. To model the Paleocene age scenario (Figure 2), we modified the present day structure contours on the Mission Canyon Formation by removing the doming caused by the Eocene igneous intrusions and an assumed steeper west to east oriented hydraulic gradient. For the paleo migration model we used a hydraulic gradient of 0.2%, nearly double the present day gradient to represent the higher eastward hydraulic drive. Such an increase is supported by Garven (1987) and Undershultz and Allan (1996).

The result of the Paleocene model demonstrates that the Shaunavon oils could have originated from the foothills region of north-central Montana (Figure 2). With a steeper hydraulic head gradient from the west, the oil is able to migrate over the Sweetgrass arch towards the northeast. Oil sourced from the prolific Bakken/Exshaw source rocks in the Foothills was likely driven over the Sweetgrass Arch up towards the Shaunavon region.

VI. MIGRATION ROUTE AND OIL SHOWS.

Migration from the western mature source rock requires vertical as well as lateral migration. Work by Dolson et al. (1993) indicates that oil has indeed migrated eastward over the Sweetgrass Arch through Mississippian carbonates, and vertically into the overlying Jurassic through faults along the arch. Another potential vertical route appears to exist where the Jurassic sands of the Shaunavon/Swift Formation onlap onto the underlying carbonates (see Figure 3). This region of permeability communication would enable the eastward migrating oil to migrate up into the Jurassic where it would continue until being trapped in the Shaunavon region.

Further evidence for a western source is in the oil shows. The region between the mature source rock region west of the Sweetgrass Arch and the Shaunavon pools has several Mississippian and Jurassic oil shows based on DST recoveries. In contrast, the region between the Williston Basin and the Shaunavon pools has no oil shows in the Mississippian or Jurassic despite many wells penetrating the Mississippian.

VII. CONCLUSION

Oil migration modelling demonstrates that the oil in the Shaunavon region of south central Saskatchewan cannot have migrated to their current position with the present day configuration of structure and hydrodynamics. Paleo modelling for migration during the Paleocene (Early Tertiary) indicates that the Shaunavon oils were generated in the Foothills region of Montana and migrated over the Sweetgrass Arch towards the northeast. This was made possible by a steeper hydraulic gradient towards the east in the Late Cretaceous/Early Tertiary and by the absence of the structural doming and upland recharge currently associated with Eocene intrusives in central Montana that dominate present day hydrogeology.
By understanding that Lodgepole sourced oil has not migrated through the region between the Shaunavon Trend and the Williston Basin, this area can be downgraded for exploration. In contrast, the migration fairway between the mature source rocks in the Foothills and the Shaunavon Trend represents a potentially rewarding area of exploration focus.

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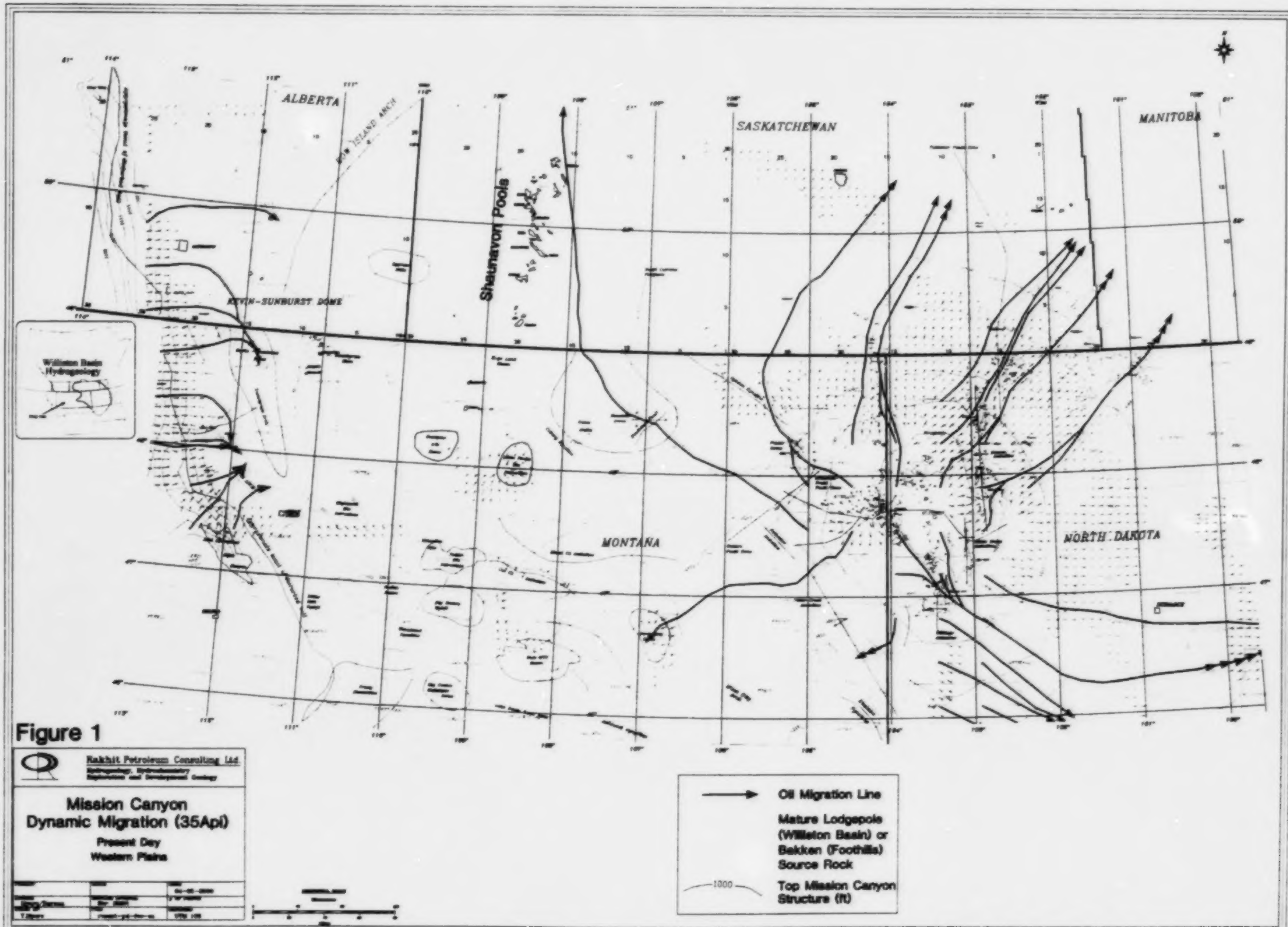


Figure 1

Rakhit Petroleum Consulting Ltd.

Mission Canyon
Dynamic Migration (35Api)
Present Day
Western Plains

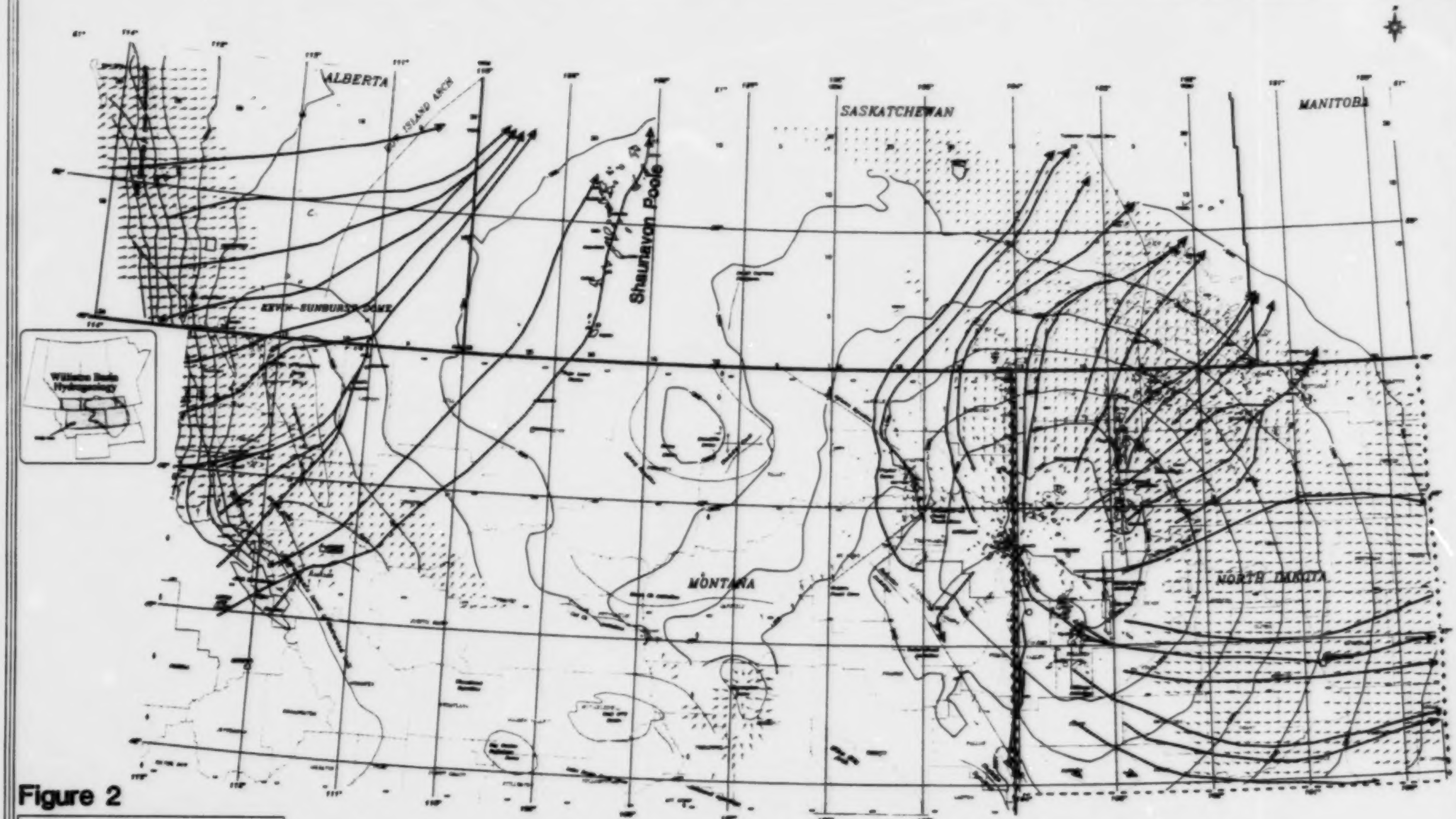


Figure 2

Bakhit Petroleum Consulting Ltd.

Mission Canyon Dynamic Migration (35API)

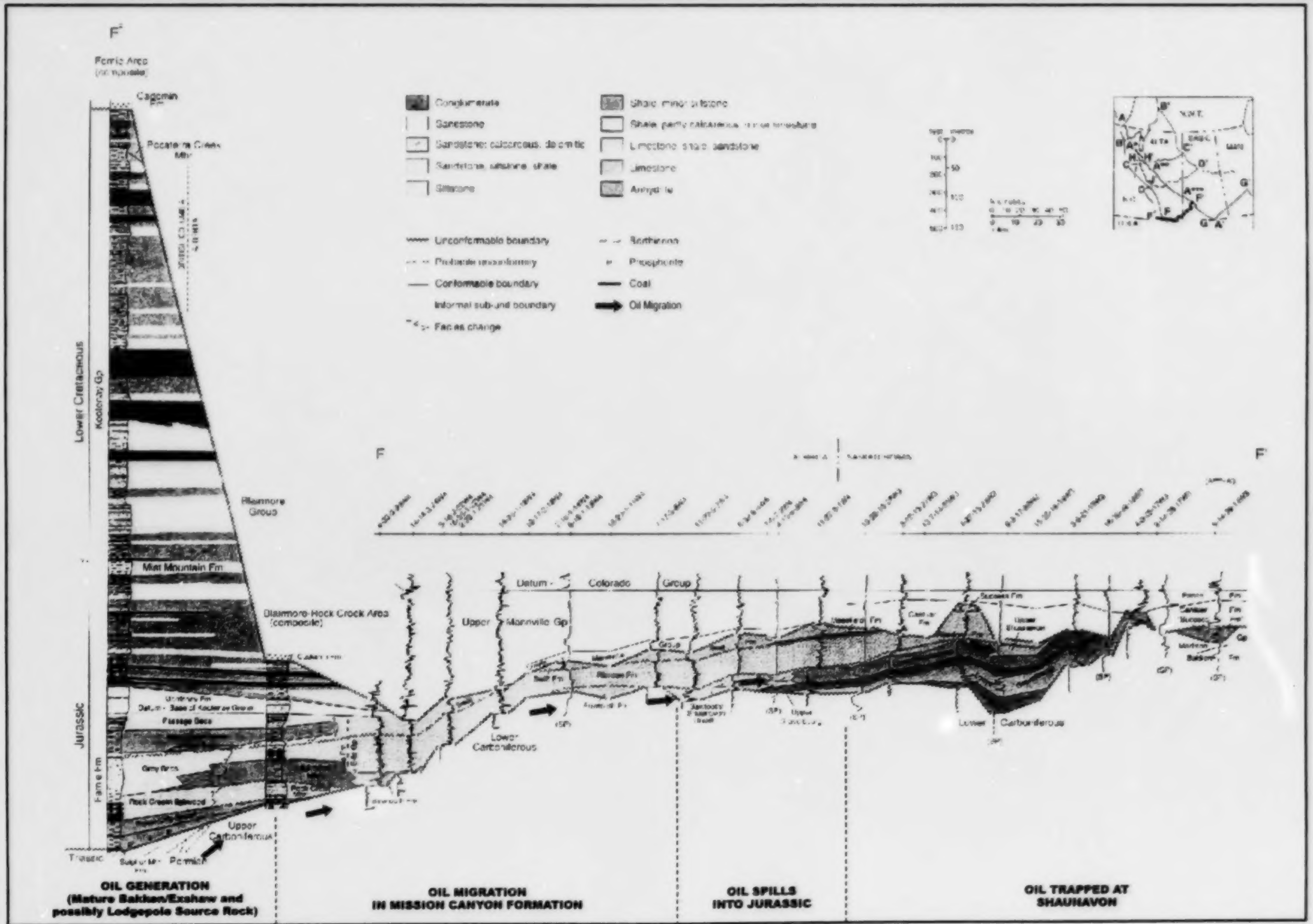
End of the Paleocene (57.8Ma)

Western Plains

Oil Migration Line

Mature Lodgepole (Williston Basin) or Bakken (Foothills) Source Rock

Top Mission Canyon Structure (ft)



Modified from CSPG Atlas, 1994

Rakhit Petroleum Consulting Ltd.	JOB	HGUS III.5	BY	LMA/TM	CROSS-SECTION SHOWING POTENTIAL OIL MIGRATION PATHWAY	FIGURE 3
	DATE	04/05/00	DRWN	LMA		
	FILE	OilXsect.cdr	CHKD	KR		

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Eighth International Williston Basin Horizontal Well Workshop

May 7 – 9, 2000
Radisson Inn Bismarck
Bismarck, North Dakota

Questionnaire

Please take a few minutes to fill in this questionnaire. Your responses will help us judge the usefulness of the workshop and evaluate whether or not these workshops should be continued. Replies will be anonymous with the exception that we would like to be able to separate comments by country. Thus please indicate in which country you are employed:

Canada ☐ U.S.A. ☐ Other ______________________

1. Should we have another Williston Basin International Horizontal Well Workshop? YES NO

2. If yes, how often do you think they should be held?
   Once a year Every other year Every 3rd year Every 4th year

3. What part(s) of the workshop do you find most useful?

4. If future workshops are to be held, what changes could be made to make them more valuable to you?

4a. It's been suggested that the emphasis of the workshop needs to change, perhaps shifting away from horizontal drilling to some other technology. Do you agree? If so, what kind of change would you suggest?

5. Should display/poster spaces be made larger even though that would necessitate limiting the number of displays?

6. If your answer to number 5 is affirmative, how would you limit the number of display/poster spaces?

7. In future workshops, on what topics would you like to have presentations?

8. Do you feel you have gotten value for your time and money during this workshop?

9. Please comment briefly on any aspects of the workshop just completed. How might we have done a better job? What did you like about the workshop? What did you dislike? Etc.

10. Please indicate your profession:

Engineering	Geology	Geophysics	Land
Sales/service	Management	Other	
	Private Industry	Government	

Thank you for your thoughtful responses.